Province of Nova Scotia

Electricity Marketplace Governance Committee

First Interim Report

December 2002

Nova Scotia Electricity Marketplace Governance Committee Website

www.gov.ns.ca/petro/energystrategy/emgc

TABLE OF CONTENTS

EXECUTIVE SUMMARY 1

1.0 INTRODUCTION 2
- 1.1 Energy Strategy Policy Objectives 2
- 1.2 Decisions Taken by the Government of Nova Scotia 2
- 1.3 EMGC Terms of Reference 3
- 1.4 Contents of this Report 4

2.0 EMGC COMMITTEE 4
- 2.1 Committee Composition 4
- 2.2 The EMGC Process 4
- 2.3 Criteria for Decision Making 5

3.0 EXTERNAL INFLUENCES ON THE NOVA SCOTIA ELECTRICITY MARKET 5
- 3.1 Economics of Electricity Restructuring 6
- 3.2 The Federal Energy Regulatory Commission 6
- 3.3 New Brunswick and Electricity Restructuring 8
- 3.4 Nova Scotia and the Energy Strategy 9

4.0 MARKET SCOPE AND BASIC MARKET MODEL 10
- 4.1 Market Scope 11
  - 4.1.1 EMGC Consideration of Market Scope 12
  - 4.1.2 Market Models 13
  - 4.1.3 Bilateral Contract Market 13
  - 4.1.4 Fully Competitive Wholesale Pool Market 14
  - 4.1.5 A Single Buyer Market 15
- 4.2 EMGC Recommendation on Basic Market Model 15
- 4.3 Market Power 16
- 4.4 System Operator 17

5.0 TRANSMISSION ISSUES 17
- 5.1 Importance of Transmission 17
- 5.2 Transmission Tariff Options 18
- 5.3 Transmission Services Offered 21
- 5.4 Transmission Tariff Design Issues 23
  - 5.4.1 Definition of Transmission and Distribution 23
  - 5.4.2 Definition of Transmission - Radials 24
  - 5.4.3 Charge Determinants 25
  - 5.4.4 Billing Determinants - Net or Gross Peak 26
  - 5.4.5 Rates - Location and Voltage 27
- 5.5 Congestion Management Policies 28
  - 5.5.1 Management of Internal Congestion 28
  - 5.5.2 Transmission Rights on the Interties 29

APPENDIX A 31
Terms of Reference 31

APPENDIX B 35
Summary of Recommendations 35

APPENDIX C 37
Glossary 37

APPENDIX D 51
NSPI Transmission Lines 51

APPENDIX E 52
NSPI Transmission Lines 52
Radials to Load 52

APPENDIX F 53
NSPI Transmission Lines 53
Radials to Generation 53

EXECUTIVE SUMMARY

The Nova Scotia Government created the Electricity Marketplace Governance Committee (EMGC), shortly after it was presented with its *Energy Strategy*. A key commitment in that document was the creation of a group that would be charged with advising the Minister of Energy on the implementation of electricity-related actions identified in the *Strategy*. Terms of Reference were created, a Chair was selected and a qualified consulting firm was retained, following a public tendering process. A key consideration in the makeup of the EMGC membership was the requirement that the committee members should represent key consumer, commercial, municipal industrial and renewable energy organizations, in order that all relevant electrical interests would be represented around the table. Deliberations were not expected to exceed one year but during that period the committee was requested to produce several interim reports at appropriate intervals. A final report is due on 31 March 2003.

To date the EMGC has devoted its attention to three issues: external influences, from global to maritime, which exert considerable influence on decision-making in Nova Scotia; defining the size and form of the short-term competitive portion of the Nova Scotia market; and a detailed consideration of the present transmission system, with special consideration given to the changes required to achieve the stated goals of the *Strategy*. The first Interim Report of the EMGC considers each of these issues and offers specific recommendations regarding transmission issues.

1.0 INTRODUCTION

Acting on a key commitment in its new Energy Strategy[1], the Government of Nova Scotia quickly established the Electricity Marketplace Governance Committee (EMGC) to advise it on the implementation of electricity-related actions identified in the strategy. The EMGC was planned as a body that would embrace a broad array of interests, so the government invited relevant stakeholder groups to nominate individuals to represent their respective constituencies as either members or alternates. At the same time the government developed Terms of Reference (Appendix A) for the EMGC, appointed a Chairperson and retained, through its public tendering process, the services of a qualified consulting company to provide the EMGC with independent technical support on electricity restructuring issues. The EMGC was charged with the responsibility of delivering a final report, containing specific recommendations, to the Minister of Energy by March 31, 2003.

1.1 Energy Strategy Policy Objectives

Nova Scotia's *Energy Strategy* defined three main goals:

- to create a world-class energy sector that would achieve sustainable economic development in balance with high social and environmental standards;
- to optimize financial, economic, and social benefits in the province's rapidly expanding offshore energy sector; and
- to improve the province's environment and enhance the quality of life for Nova Scotians.

In keeping with those goals, the *Energy Strategy* also strives to attain the following objectives, which specifically address Nova Scotia's electricity sector:

- to maintain a secure, reliable and affordable electricity supply, generated in an environmentally responsible manner;
- to encourage long-term competition; and
- to promote the growth of renewable energy sources in Nova Scotia.

1.2 Decisions Taken by the Government of Nova Scotia

The *Energy Strategy* commits the Nova Scotia's electricity industry to carefully increasing competition while simultaneously encouraging the growth of renewable energy sources within its jurisdiction. In order to achieve these results, the strategy commits the province to the implementation of the following actions:

- to establish a broadly representative committee with the responsibility of recommending to the Minister of Energy the relevant details of implementation, structure, and rules for the future development of the electricity sector;
- to provide policy direction to the Nova Scotia Utility and Review Board regarding open access transmission, on Nova Scotia Power's facilities, for all generators selling to wholesale customers or export markets;
- to introduce competition within the electricity sector in a staged and measured process beginning with supply to wholesale customers ;
- to introduce competition in future electricity generation and encourage co-generation;
- to assist with the development of a renewable sector of independent power producers by

---

[1] *Seizing the Opportunity : Nova Scotia's Energy Strategy*, December 2001 (www.gov.ns.ca/petro/energystrategy)

permitting access to the Nova Scotia Power transmission system for green-power customers, and by setting with Nova Scotia Power a voluntary target of 2.5 percent (50 MW) for new generation by the independent producers;
- to recommend information programs to promote the use of renewable energy technologies;
- to recommend steps which would lead to the eventual meeting of US reciprocity requirements for the export of electricity; and
- to make recommendations encouraging the eventual use of indigenous coal resources, and as well, the work required to support an appropriate role for coal.

Longer Term Issues

The *Strategy* also recommends two additional goals for the longer term, defined here as post 2005:

- to work with Nova Scotia Power for the long-term retrofit or replacement of generating systems; and
- to expand green energy programs, possibly including a mandatory Renewables Portfolio Standard.

1.3 EMGC Terms of Reference

Terms of reference for the EMGC were developed by Department of Energy officials, guided by the *Energy Strategy,* which resulted in the following responsibilities:

Over the Near Term

- Provide recommendations that ensure transmission system access is available to all eligible market participants on an equitable basis.
- Consider the use of exit fees or other methods for handling stranded costs.
- Address responsibility for the non-contestable market (standard offer supply).
- Identify which customers are entitled to standard offer supply.
- Define "renewable" energy for public policy purposes.
- Determine how new capacity is to be added to Nova Scotia's electricity system.
- Design a system for Nova Scotia that retains all benefits they presently enjoy, generally defined as "heritage assets".
- Provide recommendations for the promotion of co-generation.
- Determine how green power marketers should gain access to end-use customers; i.e. physical or financial transactions.
- Define the appropriate role of Nova Scotia Power relative to green power.
- Recommend methods of monitoring green power sellers to ensure that all financial transactions are appropriate.
- Define the target capacity, time frame and market participants appropriate to implement a mandatory Renewable Portfolio Standard.
- Define the circumstances when net metering would be permitted or encouraged.

Over the Longer Term (post 2005)

- Make recommendations regarding the establishment of workable competition in the Nova Scotia electricity marketplace (i.e., market power issues).
- Make recommendations on market surveillance and enforcement of market rules.
- Recommend mechanisms to permit determination of stranded costs that result from new investments or competitive supplies.

- Assess Nova Scotia's compatibility with systems in Northeastern North America (including both United States and Canadian jurisdictions)
- Consider issues of reciprocity in relation to transmission developments in both Canada and the United States.

1.4 Contents of this Report

The EMGC developed a work plan to deal with the issues that need to be resolved over its ten-month mandate. The work plan envisions an average of two meetings per month, or approximately 20 meetings in total. This First Interim Report to the Minister of Energy reports on progress made by the committee in its first ten meetings. It is devoted to three issues that were considered to be an essential foundation upon which later deliberations would rest. They include: transmission issues, especially tariff design; the scope and design of the Nova Scotia electricity market; and external forces that are at play on Nova Scotia decision-making. Since this is an interim report, decisions reached are not final, but rather should be viewed as "work in progress". Recommendations in this Interim report may be revisited if subsequent decisions require it.

2.0 EMGC COMMITTEE

2.1 Committee Composition

In keeping with a fundamental commitment of the *Energy Strategy*, the government established a small broadly based group of stakeholders that were expected to solicit the input/views of their respective constituencies. EMGC members include one representative from each of the following seven stakeholder groups:

- Canadian Federation of Independent Business, representing small and medium business;
- Canadian Manufacturers and Exporters, representing large industrial users;
- Consumers Association of Canada;
- Electricity Consumers Alliance of Nova Scotia;
- Municipal Electrical Utilities of Nova Scotia Cooperative;
- Nova Scotia Power Inc., a regulated, vertically integrated electricity service provider;
- Renewable Energy Industries Association of Nova Scotia.

In addition, the government invited representatives from the Nova Scotia Utility and Review Board and the Nova Scotia Chamber of Commerce to participate as official observers.

EMGC members have all agreed to represent the views and interests of their own organizations as well as the broader interests of their respective stakeholder constituencies. In an effort to ensure that the EMGC process is open and transparent to the public, the government created a regularly updated web site (www.gov.ns.ca/petro/energystrategy/emgc). All interested parties are invited to follow the committee proceedings by accessing the web site and/or submitting comment to their respective constituency representatives.

2.2 The EMGC Process

At the committee's inaugural meeting on May 28, 2002, members agreed to abide by the provisions set out in a document entitled *Nova Scotia EMGC Mandate and Rules of Conduct* that provides the committee mandate, along with guidelines for decision-making and internal workings. This document supplements the EMGC's Terms of Reference, which lays out specific tasks and responsibilities for the members.

To date, all EMGC meetings have been plenary sessions, each encompassing a full working day. The

chair, project manager and consultants acting on direction provided by the membership, set the agenda for each meeting.

In an effort to give EMGC members a good understanding of the important and complex issues under consideration, the committee consultant prepared issue papers and/or electronic presentations on appropriate topics. Following extensive discussion on each issue, a hypothetical "strawman" was prepared for committee consideration. Strawmen are used to lay out a detailed set of proposed options and alternatives for a specific set of issues, and as such they present a useful starting point for discussion, debate and deliberation by the Committee. The use of strawmen is an iterative process that permits continuous refinement, revision and amendment as the decision process proceeds.

All Committee members are encouraged to submit documents and/or presentation materials to the Committee. NSPI has made several useful presentations and circulated some very informative background documents. In addition, the committee received a presentation by Sir Graham Day, which provided it with some additional contextual insights, based primarily on his experience with electricity restructuring in the United Kingdom and Ontario.

The Committee agreed that it would seek to build a consensus with respect to all of its decisions. However, if unanimous consent is deemed to be unattainable, the Chair may establish a Committee position, from which members will have the right to dissent.

2.3 Criteria for Decision Making

During the third meeting of the EMGC the first issue paper, entitled *Overview of Objectives and Criteria for Decisions,* was tabled. It was discussed and ultimately adopted, thereby providing the committee with a framework for future decision-making.

The second issues document, entitled *Transmission Issues*, provided insights into the future direction of electricity markets in North America, including that of our New Brunswick neighbor. It examined the requirements for market access in Atlantic Canada and the US. It also assessed the merits of a competitive wholesale pool market in Nova Scotia and identified some important long-term issues. The paper cites two important goals of electricity restructuring: the achievement of greater economic efficiency in the supply system and the allocation of risk to the parties best positioned to absorb or control that risk.

Accepted criteria for decision-making include: reliability, transparency, fairness, robustness, enforcement ability, environmental impact and protection of existing Nova Scotia consumers.

3.0 EXTERNAL INFLUENCES ON THE NOVA SCOTIA ELECTRICITY MARKET

Discussions among EMGC members, regarding the future of the electricity market in Nova Scotia, have occurred within the very broad context of significant external change currently underway across the full extent of the electricity sector. To properly appreciate the Nova Scotia discussions, it is important to have some understanding of influences presently in play outside the province. These extend across a broad spectrum, from events at the global, North American and national levels to those that are predominantly Maritime in nature.

3.1 Economics of Electricity Restructuring

A growing number of jurisdictions throughout the world are considering, executing or sometimes even reconsidering the restructuring of their electricity industries. The predominant trend among these initiatives

involves several key elements: movement towards greater reliance on market forces to set the bulk-price of electricity; creation of greater competition in retail supply and; maintenance of transmission and distribution activities as regulated monopolies. The first countries to pursue this agenda included England, Argentina, Norway, Australia, and New Zealand.

Greater competition in electricity supply is thought to be both desirable and practical as a result of two underlying economic forces, namely, reductions in the economies of scale for electricity generation, and the rapid advances in the area of information technologies.

Thirty years ago it was widely believed that progressively larger generation facilities were more cost-efficient than their smaller predecessors. Over the intervening years greater recognition has emerged of the increased risk that can be associated with larger plants. Simultaneously, new moderate scale gas turbine technologies are now as cost-efficient as much larger plants. This has had the profound effect of moving electricity generation from the realm of natural monopolies, and having the potential to be highly competitive.

The second underlying consideration concerns the instantaneous nature of electricity. It has prevented any meaningful competition until the advent of appropriate real-time monitoring technology. Electricity is generated at essentially the same instant that it is being used, and usage can vary widely over time. Coordinating supply with demand, as for example when an operator chooses which plant to put on-line to meet changed load conditions, is the work of a centralized body or agency. However, to carry out this task at least cost demands access to full system-wide cost and technical information in order to efficiently match system supply and demand. Before the advent of high-speed information and communication technologies, only a single owner could have the necessary data. However, with appropriate technology, an independent dispatching body can now gather the necessary market data, process it, use it to affect price discovery and finally to create a dispatch schedule. It then follows that with the introduction of competitive generation it should also be possible to make the retail supply of electricity competitive.

One additional consideration worthy of mention has been a growing political movement away from price regulation and towards more open and competitive markets. The transition from fully regulated utility to market competition has necessitated the introduction of sweeping changes in most jurisdictions. These have included: a reassessment of the degree and manner of regulation; movement away from vertical integration toward unbundling; greater regional integration governed by a common set of principles, and; so as to stimulate competition, fair and equitable access to transmission capacity. In the United States these principles have been vigorously applied over the past decade through the actions of FERC which, because of the interconnectedness of the continental electricity system, is having a growing influence on decision-making in Canada.

3.2 The Federal Energy Regulatory Commission

In the United States, the Federal Energy Regulatory Commission has the authority and ability to create and enforce regulations that are applicable to most electricity industry participants. Driven towards greater competition by both economic and political considerations, FERC has been a persistent and effective motivating force behind the restructuring of electricity industry in the United States.[2] FERC's broad jurisdiction is in contrast to that of the National Energy Board which to date has only been granted authority over the export of electricity and over the construction and operation of international power lines.

After leading a restructuring of the gas and oil transmission industry, FERC's first major restructuring

[2] FERC does not have jurisdiction over retail electricity competition; the states do. The degree of retail competition therefore varies widely from state to state.

directives affecting the electricity industry appeared in 1996, as Orders 888 and 889. In Order 888, FERC determined that non-discriminatory open access transmission services, including access to transmission information, and stranded cost recovery were the most critical components of a successful transition to competitive wholesale electricity markets in the United States. In Order 889, issued concurrently with Order 888, FERC also imposed standards of conduct governing communications between a utility's transmission and wholesale power functions, to prevent the utility from giving its power marketing arm preferential access to transmission information. Under that Order utilities owning, controlling or operating transmission facilities were required to create or participate in an Open Access Same-Time Information System (OASIS) so that existing and potential transmission customers could have real-time and non-preferential access to information about available transmission capability, prices and other matters affecting the transmission system.

Order 888 contained a *pro forma* Open Access Transmission Tariff (OATT), the use of which would constitute compliance with the FERC directive for non-discriminatory open access transmission services. Together, the Orders required that public utilities were to be functionally unbundled. This meant (1) that such utilities were to take wholesale transmission under the same terms as offered to customers, (2) they were to state separate rates for wholesale generation, transmission, and ancillary services, and (3) they had to rely on the same electronic information system that transmission customers rely on to get information about the transmission system.

Some additional features of the open access approach included: giving priority rights to existing customers who committed to power on long-term contracts; making certain that any short-term excess transmission capacity be made available to any market participant who requested it, and; designing rules to prevent utilities that own both generation and transmission facilities from discriminating against other market participants.

As a means to further encourage additional non-discriminatory access to transmission systems, FERC,s *pro forma* OATT also included a reciprocity provision. Under this provision all customers (and their affiliates) that own, control or operate interstate transmission facilities and that take service under a public utility's open access transmission tariff must offer comparable (not unduly discriminatory) services in return. These provisions addressed organizations that owned both generation and transmission; they required that access be made available to the organization's transmission system if it was to have access to those in neighboring jurisdictions. While this provision was aimed primarily at utilities in the United States outside of FERC jurisdictions, such as cooperatives, it also affected Canadian utilities. For example, in response to the FERC Orders Quebec restructured Hydro-Quebec into quasi-independent generation and transmission arms. This resulted in a FERC license, which permits Quebec to access the neighboring transmission network to market electricity in the United States.

Response to the FERC Orders by American utilities was a significant restructuring of electricity generation and an increase in competition. In many states, especially those that adopted retail competition, vertically integrated utilities were forced or encouraged to sell off their generation assets and several regions created competitive wholesale pool markets. However, many generators continued to complain that transmission owners discriminated against them. Also, differences between markets led to difficulties when trading electricity across borders.

FERC responded to these difficulties by issuing Order No. 2000. This was FERC's second major step towards establishing competitive wholesale power markets and eliminating residual undue discrimination in interstate transmission services. Its object was to have all transmission owners in the US voluntarily place their transmission facilities under the control of appropriate regional transmission organizations (RTOs). FERC concluded that establishing independent RTOs would eliminate undue discrimination in transmission, enhance the benefits of competitive electricity markets and could improve efficiency in transmission grid

management and reliability. Each RTO would encompass a single transmission market, allowing generators to move electricity over long distances without incurring additional transmission charges, and as well each RTO would be responsible for dispatch within its area. In later rulings, FERC made it very plain that it envisioned only four or five very large RTOs, extending across the United States. As of the summer of 2002 however, only one RTO has been fully approved by FERC.

Full access to transmission within an RTO is provided with full membership. However, that membership also carries the reciprocal responsibility to accept control by the RTO, which for Canadian utilities implies a potential loss of sovereignty. The Canadian response was mixed so that some utilities joined an RTO, while others created parallel but coordinated systems that readily traded with a neighboring RTO. The FERC reciprocity requirement remains in effect, so that Canadian utilities that desire access to US transmission systems must offer reciprocal access to their systems or otherwise qualify for a waiver or exemption under the "safe harbor" provisions of the FERC Order.

Dissatisfied with the pace of RTO formation, and still insisting that trading should encompass broad geographical areas, FERC issued a Notice of Proposed Rulemaking (NOPR) in July 2002, for a Standard Market Design (SMD). If eventually enacted, these proposed rules would enforce a high degree of commonality on market design in all of the RTOs. FERC has met substantial resistance to its NOPR, so that its ultimate disposition remains highly uncertain. Regardless of the ultimate fate of the August 2002 proposal, the Orders already in play are extending their reach into the Maritimes, most notably with their influence on plans, regulations and expectations in our neighbor province of New Brunswick.

3.3 New Brunswick and Electricity Restructuring

The New Brunswick electricity industry is dominated by a vertically integrated, government-owned monopoly, New Brunswick Power. NB Power uses a mix of generation technologies and fuels, but it relies heavily on its Point Lepreau nuclear unit along with several large fossil-fired units.

New Brunswick reacted to the global and continental changes in the electricity market described above by initiating a public consultation process to consider future electricity options. This process resulted in the release of a *White Paper* in 2001.[3] In it, the government committed to creating a limited competitive electricity market by April 1, 2003. The proposed market design would allow both wholesale customers (i.e., municipal utilities) and large retail customers directly connected to the transmission system (i.e., those with connection capacity of 750 kW or more) to choose competitive suppliers. Combined, these user categories make up approximately 30% of total demand. To facilitate competition, competitive generators would get non-discriminatory access to the transmission system.

New Brunswick Power relies on power exports to New England for a significant fraction of its revenue. Profits on these exports have kept New Brunswick's domestic electricity prices lower in some years by as much as 15%. Therefore, a driving force behind the White Paper commitment to open access transmission was the need to preserve and enhance access to New England markets for New Brunswick power.

To further this direction, the Government of New Brunswick appointed a Market Design Committee[4], a multi-stakeholder group, to make recommendations to the Government on implementing the electricity sector policies outlined in the White Paper. In keeping with these recommendations and with prior

---

[3] Government of New Brunswick, Ministry of Natural Resources and Energy, *White Paper: New Brunswick Energy Policy*, January 2001.(www.gnb.ca/0085/toc.htm)

[4] www.nbmdc-ccmnb.ca

commitments, New Brunswick Power has created and filed an OATT with its regulator. The OATT contains proposed reciprocity provisions that permit the New Brunswick system operator to deny Nova Scotia sellers access to the New Brunswick transmission system if the former does not have a similarly open system. This provision in the New Brunswick OATT is but one example of the constraint exercised on Nova Scotia by the fact that its only existing access to electricity markets outside Nova Scotia is through the connection between the two provinces.

3.4 Nova Scotia and the Energy Strategy

In 2001 Nova Scotia also embarked on a consultative process to examine provincial energy policy, which resulted in the release of an *Energy Strategy*.[5] However, because Nova Scotia enjoys significant coal and gas resources the strategy focused more heavily on broader areas of energy development than did New Brunswick. One sector that received considerable attention in the *Energy Strategy* was the structure of the electricity supply industry. That industry is characterized by a vertically integrated, investor-owned monopoly utility (Nova Scotia Power Inc.)

The Nova Scotia electricity industry has not been as export-oriented as that in New Brunswick, due in part to the difficulties inherent in accessing the American markets. However, Nova Scotia does have important transmission links with New Brunswick, which both Nova Scotia Power and New Brunswick Power have used to the advantage of their respective customers. Sharing of reserves with New Brunswick has been of considerable importance to both provinces in that it has obviated the need to build as much reserve capacity as it would otherwise have been required to maintain such a high level of reliability. Also, the link with New Brunswick permits the export of power to Prince Edward Island.

The Nova Scotia *Energy Strategy* explicitly states the intention to approach electricity competition gradually and carefully. The first step would open competition of the wholesale market (i.e., municipal distribution utilities) that constitutes less than 2% of total electricity demand in the province. This degree of market opening is similar to that created in Quebec, where it was deemed sufficiently reciprocal for FERC to grant Hydro-Quebec transmission access in the United States. Throughout the intended changes, NSPI would continue to have an obligation to serve electricity consumers in the province.

For Nova Scotia electricity producers to export power, they must be able to access transmission into and (for sales to the United States) out of New Brunswick. Sales either to consumers in New Brunswick or to consumers in the United States must use transmission lines in New Brunswick. A major issue in the Nova Scotia electricity market restructuring, therefore, is whether the changes made in Nova Scotia will give Nova Scotia electricity producers and consumers the right to non-discriminatory transmission access in New Brunswick and beyond.

EMGC discussions have at various times touched on most of the issues raised above. The group has repeatedly reflected on the obvious size of even the smallest American RTO, the enormous pressures that can be brought to bear through a centralized regulatory body such as FERC, the potential for loss of independent decision-making, and the inescapable downside of not attempting even a modicum of change in an otherwise rapidly changing world. The EMGC believes that Nova Scotians must accept the change that surrounds them and adjust to it in ways that reflect their native values. It is for that reason that the changes proposed by the framers of the *Energy Strategy* are conservative and incremental.

Although FERC is a legally constituted body empowered to regulate energy activities in the United States,

---

[5] Government of Nova Scotia, *Seizing the Opportunity: An Energy Strategy for Nova Scotia*, 2001.

its influence is strongly felt in Canada. This is the inescapable result of the large volume of cross-border trading which has developed broadly across the energy sector but it is especially noteworthy in electricity. FERC orders, which are designed to bring about change in American behavior, emphasize new approaches such as, for example, the concept of reciprocity. Canadians dealing with the American market are naturally expected to exhibit reciprocity with the Americans but also feel compelled to enforce similar changes within their own country, for example, in the proposed OATT under review in New Brunswick. The New Brunswick OATT, if implemented, will extend the American version of reciprocity to business practice between New Brunswick and Nova Scotia. The concept of reciprocity is not the issue; the long reach of FERC as a real and present influence on Canadian self-determination certainly is. It is a very significant external presence on local decision-making and on EMGC deliberations specifically.

Canadians may be at some disadvantage when dealing with FERC since negotiations are invariably conducted, as a result of constitutional guarantees, province-by-province. FERC, as an instrument of policy, speaks for the U.S. federal government. A FERC equivalent does not exist in Canada. The National Energy Board (NEB), although a significant presence in the continental natural gas sector, and international electricity trade, is a very much smaller presence in the area of domestic electricity policy. Since discussion and mediation are not normally conducted between FERC and NEB the responsibility naturally devolves to individual provinces. For the larger provinces this may be less of a disadvantage but for the Maritimes where the entire population is less than that of Greater Boston it is daunting, especially since the provinces seldom coordinate their activities, generally preferring to "go it alone".

EMGC discussions have ranged widely over these issues. External advice to the committee along with internal deliberations eventually converge on the possible benefits of a seamless Maritime region. Further integration of electricity interests among the three Maritime Provinces could provide economies of scale, greater operating efficiencies, a larger market offering consumers a greater degree of choice, and reduced vulnerability to external forces presently being felt in this region. The degree and nature of further integration also involves political and policy questions.

4.0 MARKET SCOPE AND BASIC MARKET MODEL

In Nova Scotia, the choice of a basic market model depends largely on the resolution of a single question: how much of the market should be open to competition? The *Nova Scotia Energy Strategy* stated that the electricity market would initially be open to wholesale customers, presently the six municipal utilities, who constitute less than 2% of the electricity demand in the province. That modest percentage severely restricts the possibilities for models that are likely to create any real competition in Nova Scotia's electricity market. Opening up the marketplace to greater competition, immediately, or in the reasonably near future, would provide a greater range of choices. Because of this small-market limitation the EMGC decided to consider the possible scope of a future market prior to offering any opinion on a basic model.

4.1 Market Scope

The *Energy Strategy* enunciated an important objective regarding electricity, namely, "To phase in competition in the Nova Scotia electrical industry."[6] It also identified "a very careful and controlled transition", which had been recommended by stakeholders, as the approach of choice. These statements make it clear that the framers of the *Energy Strategy* did not contemplate any sudden transitions to a more broadly competitive market. EMGC members, however, felt that this warranted some additional discussion. Specifically, they attempted to determine whether more of the market, above the recommended 1.6%, should be opened to competition, and if so, what sort of schedule should be employed.

---

[6] *Energy Strategy*, Volume 2, Part III, Electricity, Pg. 4

The Committee noted that the degree of market opening identified in the *Energy Strategy* appears to be the bare minimum to meet the requirements for reciprocal access required by the Federal Energy Regulatory Commission (FERC) in the United States. In order for affiliates of transmission providers to obtain access to US electricity markets, the transmission provider must offer equivalent and non discriminatory transmission access at the wholesale level. Quebec is a working example of that principle in Canada. While the Nova Scotia industry risked the loss of only 1.6% of demand by opening the wholesale market, the *Energy Strategy noted* that it "may be afforded an opportunity to increase significantly the quantity and profitability of electricity exports..."[7]

Access to that United States export market is limited initially by the size of the transmission connection between Nova Scotia and New Brunswick, and subsequently by the lack of capacity on the lines between New Brunswick and Maine. An analysis of the electricity export potential from Nova Scotia requires some understanding of present constraints. First, the intertie with New Brunswick is limited, with a maximum outbound flow of 350 MW. Second, the 700 MW intertie between Maine and New Brunswick is largely committed for the next twenty years to NB Power on the Canadian side of the border, and to a select group of power marketers on the American side. Any transaction depending on access to the intertie will have to be negotiated with the existing rights owners. Added to that are further constraints in Southern Maine, New Hampshire and Massachusetts. One solution to this problem would be to construct new transmission lines to accommodate the required access. However, significant permitting and cost recovery issues make that a difficult option. For example, a new transmission line proposed almost ten years ago for New Brunswick to Southern Maine, has not yet been permitted nor has a firm date for construction been identified. The final constraint concerns the long term availability of fuel, most likely natural gas, which would be required to justify the construction of new generation. Natural gas availability is presently dependent on the discovery and exploitation of offshore reserves, beyond the current Sable project. The full extent of those reserves is not yet clear.

Despite the constraints between Nova Scotia, New Brunswick and Maine described above, these transmission links may also facilitate an increased level of commercially viable electricity transactions among market participants in this region if/when NB Power's proposed OATT is approved; assuming that Nova Scotia takes steps necessary to meet New Brunswick's proposed reciprocity provisions.

4.1.1 EMGC Consideration of Market Scope

The EMGC believes that true competition in electricity supply in Nova Scotia will require the entry of competitive generators. Demand from the municipal utilities alone, which together have a peak load of under 50 MW, is simply not large enough to prompt competitive entry. Even if a competitive entrant could capture that entire load, it would be unable to justify building a plant the size of those commonly built in North America, at the present time. Therefore, limiting competitive choice to the municipal utilities severely limits the potential for competition in the market. Because of the market's small size, questions arose as to whether there would be sufficient financial returns to participants to achieve the goals set out in the *Energy Strategy*.

One additional consideration, on the part of the EMGC, was a reluctance to adopt a market reform that might have to be reversed if the market were to move towards greater competition in the future. The committee felt, that if a model was indeed chosen in the near future, then it should be done so as to be compatible with the EMGCs recommendations in this area.

---

[7] Ibid, pg. 15

Choices relevant to market scope are: to simply restrict the market to the minimum specified in the *Energy Strategy* [wholesale customers, renewable energy generators, co-generators and exporters]; or to open more of the demand to competition. In the latter case this can be done, as has occurred in other jurisdictions, through a long-term gradual process starting with the largest customers and working downward until full retail competition has been achieved. The UK, for example, took ten years from the start of the competitive bulk power market to full retail competition.

Alternatively, opening markets to competition can also be immediate, with both wholesale and retail components opened simultaneously. Given the clear preference here for careful and deliberate change, the EMGC did not consider an immediate opening as an acceptable choice for Nova Scotia. At any rate, any discussion of market opening, whether rapid or slow, should consider both the benefits and risks to potential market participants.

As a possible incremental expansion of market scope, the EMGC explored the option of allowing large industrial customers in the Nova Scotia market to choose competitive electricity suppliers. Large industrial customers can be defined as customers with maximum demand over 1.8 MW. Nova Scotia has approximately 40 such customers, constituting over 25% of total electricity demand. Most of them are already connected directly to the transmission system. Opening competition to these industrial customers would significantly increase the amount of electricity open to competition. It may have a major impact on market design, provision of ancillary services, the system operator, the structure of NSPI, the design of the transmission tariff, the provision of standard offer service and stranded costs.

The focus of the EMGC during the period leading up to this report has been largely on transmission tariff issues. Once these have been resolved, the Committee will be able to make a recommendation on market scope.

4.1.2 Market Models

The Committee discussed several models of electricity markets. The existing model extant in Nova Scotia is that of a vertically integrated monopoly utility, Nova Scotia Power, Inc., a private corporation and subsidiary of Emera Inc. This model could continue if the market is not opened beyond the wholesale customers. NSPI could remain under single ownership, though the transmission operations would be functionally separated if the transmission system is to meet independence criteria laid out in FERC Order 888.

Three other models discussed by the EMGC include:

- A market based on bilateral contracts between generators and wholesale and large industrial retail electricity buyers;
- A spot market organized around a bid-based pool administered by an independent system operator (ISO); and
- A single buyer/reseller market.

Every competitive market provides for both spot and bilateral market trading. The difference between a spot and a bilateral market is therefore matter of degree, rather than of kind. These differences of degree can nevertheless still be significant in the operation of the market and in its transaction costs. The essential element is not the kind of trading, but whether there is a centrally administered pool for electricity trading in the region.

4.1.3 Bilateral Contract Market

Wholesale market bilateral contracts are agreements between electricity generators and wholesale customers for the delivery of electricity. They can be financial or physical bilateral contracts. A financial contract specifies the amounts and time of the delivery of electricity and the price or price formula for the settlement. The actual generation and delivery take place according to the rules of the market, and the participants to the financial bilateral contract then settle between them any differences between their contract price and the price in the market.

A physical bilateral contract specifies amounts of injections and withdrawals, the timing of the injections and withdrawals, and the points on the system where they take place. These conditions are scheduled with the system operator. To be an effective contract, a physical bilateral must also include transmission rights between the injection and withdrawal points.

The bilateral contract model allows for the bilateral contracts to be essentially fringe competition to an existing dominant generator. Over time, the bilateral contracts could be expected to increase as a fraction of the total market, creating more competition. Such a bilateral contract market represents one way to implement a gradual approach to introducing competition in electricity supply.

A bilateral contract market does require several other conditions. Most important is that there must be open and non-discriminatory access to the transmission system for all potential buyers and sellers. To fulfill the bilateral contracts, the seller must transmit electricity to the buyer. If the transaction is subject to either arbitrary pricing or arbitrary scheduling by a system operator who is essentially a competitor of the supplier, the market is not likely to be competitive. Additional conditions for a competitive market to develop include a sufficient number of potential customers and a market price sufficiently high to attract new entrants.

A characteristic of a bilateral market is that it promotes the development of a wide range of contractual arrangements and terms.

For a small market, such as Nova Scotia, a major advantage of a bilateral market is that it is likely to have lower transition and administrative costs since it may not require the creation of a new market operator. Other advantages of a bilateral contract market are:

- Bilateral contract markets have lower price volatility than competitive pool markets, since prices for most traded electricity are based on contract terms; and
- In general, bilateral contract markets are less susceptible to the exercise of market power than either of the other models considered.

The major disadvantage of a bilateral contract market is that it does not create strong incentives to move market prices towards short term marginal cost. Prices are set by the contract terms. Prices in the balancing market can be set on a cost basis, but that market affects a relatively small fraction of the total energy traded.

The bilateral market also may have higher transaction costs for market participants. Each transaction requires a separate negotiation and the completion of a contract. Other disadvantages of bilateral contract markets include:

- The price-setting process is less transparent than it is in competitive wholesale pool markets;
- The market operator may not be independent of other market participants, creating the

possibility of actual or apparent bias; and
- A dominant supplier in a bilateral contract market could use its supply position and its customer relations to deter entry by contracting to meet all actual and expected demand.

4.1.4 Fully Competitive Wholesale Pool Market

This model requires the creation of a region-wide competitive wholesale "pool", in which an Independent System Operator (ISO) administers a regional dispatch based on offers and bids submitted by market participants. This is the form of competition adopted by many jurisdictions that have restructured and is mandated in the Standard Market Design (SMD) of the FERC Notice of Proposed Rulemaking (NOPR) of July, 2002. The market has many sellers who compete with each other. Typically, there are multiple wholesale buyers. Most Independent System Operator-pool (ISO-pool) jurisdictions have multiple distribution companies who essentially purchase their net electricity requirements from the pool and resell it by passing the wholesale price through to their end-use customers. Other wholesale buyers can include other resellers and large electricity users.

Prices in the wholesale pool are based on competitive offers and bids submitted by market participants. The actual dispatch is based on the same offers and bids from buyers and sellers in the market. Prices are derived from the dispatch and the offers and bids, and generally define the price that exactly clears the market. For example, the market-clearing price may be that price at which the price for the last increment of electricity offered to sell is equal to the price of the last increment of electricity offered to buy.

Competitive wholesale pool markets have several advantages. The most important of these is that, in the absence of market power, they have a strong tendency to drive prices towards incremental generation cost. Such prices send a strong signal to purchasers from the pool as to the costs of their usage of electricity, and lead to economic efficiency.

Other advantages of competitive wholesale pool markets are:

- They provide transparency in both price and price setting;
- The spot market can be highly liquid;
- They provide a basis for trading other energy contracts, such as contracts for differences or energy derivatives; and
- Costs of market transactions are low.

Competitive wholesale pool markets also have several disadvantages. Perhaps the most important are the set up and ongoing administration costs. Other disadvantages of competitive wholesale pool markets include:

- Greater price volatility. Matching prices to marginal costs, which change hourly, inevitably creates price volatility. But periods of shortage or crises can create much greater volatility and price spikes.
- Competitive wholesale pool markets are susceptible to the exercise of generator market power.
- Incentives for new generation investment other than market price signals are not clear.
- Incentives for new investment in transmission may not be clear. The benefits of new transmission go to customers and generators who gain access to more favorable markets, but there are no easy mechanisms for those who receive the benefit to pay for the investment.
- Competitive wholesale pool markets can be complex and require extensive training and experience for market participants.

4.1.5 A Single Buyer Market

The Single Buyer Model for electricity restructuring is centered on the principle of monopsony, a monopoly buyer facing competitive suppliers. It is a first step towards competition from a vertically integrated monopoly utility structure. This model can be implemented in a number of ways . The generation assets of the formerly vertically integrated utility can be sold to several investors, and long-term power purchase agreements (PPAs) established between the monopoly buyer and the new generation companies. Alternatively, the vertically integrated utility can be maintained and it can acquire power through a competitive bidding process or other market-based processes.

The single buyer model might be appropriate for Nova Scotia during a period when under 2% of the market is open to competition. With its dominance, NSPI will have better ability to manage the market centrally than would any of the individual utilities.

4.2 EMGC Recommendation on Basic Market Model

If the degree of competition is restricted to the wholesale market, there is no compelling need to establish a formal market with a system operator and other appropriate institutions. If the EMGC envisions an expansion to greater competition (say, to large industrial customers) either immediately or in the near future after market opening, then it might recommend adopting a market model appropriate to that size. The decision on a market model will also follow the decision on market scope.

4.3 Market Power

The *Energy Strategy* did not envision changing the essential role of NSPI with the introduction of competition; it described NSPI as continuing to be " a regulated cost of service utility with an obligation to serve." NSPI currently controls 97% of generation in the province. Without horizontal disaggregation of NSPI, it will be a dominant seller in any electricity market in Nova Scotia.

Introducing competition requires competitors. The independent generators in Nova Scotia currently serve only their own loads. Under current market conditions, any generator wishing to sell power in the Nova Scotia market would have to sell to NSPI. Such market conditions generally do not invite entry.

In a market like Nova Scotia, the greatest potential for new generation appears to be with the combined production of heat and power, or cogeneration. Cogeneration can be cost-effective for industries with an internal demand for heat, especially process steam. It can be even more effective for industries which have a source of energy, such as the use by the forest products industry of waste wood resources. However, without the ability to sell surplus energy, cogeneration is often uneconomical because of the purchase rates offered by the integrated utility.

Another source of new generation promoted by the *Energy Strategy* is power from renewable resources, owned by independent power producers (IPPs). Such producers need access to markets just as do other new generation facilities, though renewables tend to be smaller. The *Energy Strategy* proposed finding ways to give such potential entries special treatment. When a significant amount of new supply from renewable resources becomes available, they can begin to challenge the NSPI monopoly, at least with respect to some kinds of customers.

Ultimately, market power derives from the existence of barriers to entry; if entry is free, any excess profits

earned by existing companies will be quickly competed away by new entrants. Of course, entry cannot be completely free in electricity generation; it takes time and some unrecoverable investment to compete. But markets can be made more competitive by opening demand to competition and by mitigating all but the essential barriers to entry.

The barriers discussed included: lack of access to the transmission system; lack of access to suitable sites for generation; lack of access to essential inputs for generation; lack of access to transportation for generation fuels; and lack of market liquidity.

In Nova Scotia, no one generator can expect to control more than a few of what are likely to be many potentially suitable sites for electricity generation. The essential inputs to generation (other than fuel) are personnel and equipment, which are generally available.

Therefore, possible sources of market power in Nova Scotia are access to fuels and fuel transportation, access to the transmission system, and access to a liquid market for the product. Of these, the barriers which the EMGC can address are access to the transmission system and the creation of a liquid market. Both of these are conditions that give potential generation entrants some assurance that they will be able to market their products. In the context of market liquidity, the discussion also noted the importance of the pricing of the balancing services, which could represent a threat to the economic viability of an entrant.

Without non-discriminatory transmission access, even if new entrants could match existing companies in resource availability and costs, they could not successfully enter the market. Again, therefore, the focus on market development in Nova Scotia is a focus on ensuring transmission access. It is also clear that the more of Nova Scotia demand is made contestable, the more likely it is that a competitive supplier will enter to serve that demand.

4.4 System Operator

The nature of and the need for a system operator will depend on the choice of market scope and basic market model. If the market is limited to the wholesale customers, and NSPI remains a vertically integrated utility with an obligation to serve, there would be little need for a fully independent system operator. Under FERC Order No. 888, the transmission service provider can be a transmission owner affiliated with a generation owner. The transmission service provider is, in effect, the system operator. It is not independent of generation.

Alternatively, if a more competitive market were to exist, there would be more scope for an independent system operator. The EMGC will discuss the issues relating to a system operator - its governance, structure, roles - after the decision on the basic market model.

5.0 TRANSMISSION ISSUES

5.1 Importance of Transmission

Access to transmission is the key to effective competition in electricity supply. The transmission system is the essential channel for moving electric energy as well as the provider of associated ancillary services. Assured access to transmission is an essential first step toward market implementation. It is for that reason that the EMGC decided to make transmission access the first item for discussion on its agenda. This naturally led to a review of the various external pressures that are regularly experienced by the Nova Scotia electricity supply system, most notably the continuing influences emanating from New Brunswick and New England. In addition, the EMGC deliberations also embraced issues that are of immediate interest to Nova Scotia Power Incorporated (NSPI) which is presently in the process of developing a Transmission Tariff.

This, in turn, led to in-depth discussions on the issue of tariff design and eventually to he more detailed questions of cost allocation and billing determinants, among others.

The Nova Scotia *Energy Strategy* calls for the introduction of "competition within the electricity sector in a staged and measured process beginning with supply to wholesale customers; specifically the six municipal utilities". To enable wholesale customers to obtain competitive supply, they must be able to obtain transmission service from NSPI in a non-discriminatory manner. That is, potential wholesale users and/or competitors should not be arbitrarily precluded from the market by the lack of access to transmission or resulting from the administration of a tariff.

Giving customers transmission access, in even a limited fashion, does require a major change, at least in the manner used to account for electricity service. Under this scenario, only electricity generation would be open to competition. Potential customers will not buy from competitive generators unless the delivered costs of electricity, including generation, transmission and distribution, can be specified. However, at the present time rates are bundled, which means that the customer buys several products simultaneously - electricity, ancillary services, transmission and distribution services - for one inclusive price. So, in order to allow transmission access, transmission prices must be separately identified. That requires the creation of a transmission tariff where transmission would be priced independently of other products.

To implement these views, the EMGC adopted the following recommendation.

Recommendation 1-1. The EMGC recommends that NSPI develop and file a transmission tariff.

Transmission pricing is generally designed to avoid favouring one market participant arbitrarily over another. It is also used to avoid the creation of artificial barriers that might discourage construction of new generation capacity. Meeting these simple conditions can be difficult, given the technical complexity of a transmission system and the need to ensure reliability of supply. Transmission costs are part of any electricity sales transaction. Transmission tariffs should reflect costs imposed on the system by the transaction. If the transmission costs are artificially high or low, they lead to artificially high or low prices to the customer of the traded electricity, and therefore to a distorted allocation of resources.

For example, radial lines that exclusively serve specific generation are as much a part of the cost of that generation as are the turbines. If the cost of such lines is included as part of the general transmission costs, as opposed to being assigned directly to generation, then all transmission users pay those costs. In effect, such assignment forces one generator to pay part of its competitor's costs. That puts competitive generation at an artificial disadvantage.

The EMGC agreed with the basic principles of transmission tariff design in adopting this recommendation.

Recommendation 1-2. The EMGC recommends that any transmission tariff developed for use in Nova Scotia ensure open and non-discriminatory transmission access for all market participants.

5.2 Transmission Tariff Options

Before considering Nova Scotia, it might be useful to review the most commonly used framework for the provision of transmission service in North America, known as the Open Access Transmission Tariff. In 1996, the United States energy regulator, the Federal Energy Regulatory Commission (FERC), issued two major orders, referred to as 888 and 889. The purpose of these orders was to ensure that the part of the nationwide transmission system under FERC's jurisdiction would be open to non-discriminatory access for

any parties wishing to make electricity sales transactions. A central part of this approach was the requirement that all transmission service providers regulated by FERC create and file for approval an Open Access Transmission Tariff (OATT) within a specified time. FERC Order 888 contained a *pro forma* tariff, which transmission providers could adapt for their systems. An important result of the OATT was to make transmission procedures and costs transparent. The ultimate goal of the FERC initiative was to encourage competitiveness in electricity markets in the United States.

The impact of FERC Orders 888 and 889 has also been felt in Canada. A majority of Canadian Provinces have implemented FERC compliant OATTs in response to the US requirement that such tariffs be in place for all generators with transmission-owning affiliates to receive market-based rate authority. Many Canadian entities currently offer open access transmission service which is comparable or superior to that offered by U.S. transmission providers, although not all Canadian tariffs or market rules governing transmission services are alike. Following is a summary of Canadian provincial participation.

- BC Hydro has a wholesale Transmission Services Tariff which uses the FERC Order 888 pro forma basis for its structure and content.
- Although Alberta does not have a FERC Order 888-type open access transmission tariff (OATT), it has a "made-in-Alberta" open access tariff that satisfies FERC's comparability/reciprocity provisions.
- SaskPower has posted a modified FERC Order 888 pro forma tariff OATT which provides U.S. and Canadian wholesale customers non-discriminatory access to the transmission system.
- Manitoba Hydro has an OATT and a Coordination Agreement with MISO (its independent system operator) on file with FERC that requires Manitoba Hydro and MISO to have comparable, non-discriminatory access, transmission service charges and congestion management procedures.
- In an order dated September 26, 2002, FERC found that Ontario's "Independent Market Operator" (IMO) provides open access transmission service on a comparable, non discriminatory basis for wheeling through and out of Province.
- FERC has recognized Hydro Quebec's TransEnergies (Quebec's functionally separated transmission entity) OATT as being comparable to that offered under FERC Order 888.
- In July of 2002, NB Power filed with its regulator an application for a FERC Order 888 compatible OATT. The hearing on this tariff is currently underway.

Requirements for additional infrastructure and administration, which emerge with adoption of a FERC OATT, are not insignificant. For example, FERC Order 889 requires that transmission providers functionally separate their transmission operations from their generation business. This is to ensure that the affiliated generator will not gain advantage through access to either operational information or to the transmission system, itself. Order 889 also requires the creation and administration of an Open Access Same-time Information System (OASIS). This is an INTERNET-based platform for posting information pertaining to the status, available capacity and pricing on the transmission system. Transmission customers are required to use the provider's OASIS in order to obtain relevant information and to book service.

Navigant Consulting estimates the cost of implementing an OASIS and functionally unbundling the NSPI transmission system to fall between $4 million and $9 million. The actual amount will depend on the regulatory review, the extent of functional unbundling , and the actual cost of developing the OASIS. Incremental ongoing administration costs are further estimated to range from $1.5 to $2.0 million. Alternatively, NSPI estimated initial costs to be about $2.1 million. All estimates, from both sources, are acknowledged to be very preliminary first approximations.

With costs of this magnitude, serious consideration was given to whether an OATT would be required at this

stage in the development of the Nova Scotia market. One possibility would be to implement an OATT, but not an OASIS, thereby deferring the latter cost. It could be added later when sufficient generation, or an increased level of contestability, warranted it. An OASIS is an important tool to ensure that transmission access is non-discriminatory, and the absence of this capacity will very likely be viewed unfavourably by potential developers of new generation. To provide merchant generators additional comfort to undertake this market risk, formal criteria could be defined to identify the threshold appropriate to implement an OASIS.

Another option, to keep costs low while providing essential service, would be to discuss the possible sharing of the New Brunswick OASIS with its system operator for scheduling transmission in Nova Scotia. Since little congestion is anticipated in this province, at least initially, it might be possible, with little additional cost, for the New Brunswick OASIS to also schedule transmission in Nova Scotia. Scheduling transfers between the two provinces might also offer advantages if done through the New Brunswick system, since a Nova Scotia user of the interconnecting lines must also use the transmission system in New Brunswick.

Pressure is building from New Brunswick to adopt a FERC-compatible tariff. New Brunswick Power has filed an application with the New Brunswick Board of Commissions of Public Utilities (PUB) for a fully FERC compatible (888/889) OATT. It is clear from the proposed tariff, as well as from NB Power's responses to Information Requests, which are part of the preparatory activities leading up to the hearing, that NB Power regards reciprocity with Nova Scotia as a requirement. Reciprocity, in this case, means that potential users of the New Brunswick system will require a FERC-compatible OATT. This applies specifically to NSPI and its affiliates but not to independent Nova Scotia generators.

In July, 2002, in the United States, FERC issued a Notice of Proposed Rulemaking (NOPR) which is intended to eventually bring about a standard market design (SMD) in all markets under its jurisdiction. The NOPR contains a modified *pro forma* tariff. FERC is building on the existing OATT structure despite the fact that some elements of the SMD have impacts that go well beyond the OATT. At this time, any attempt to adopt a transmission tariff in Nova Scotia, compatible with the proposed SMD, would carry with it considerable risks, since the specifics of such a tariff have not yet been defined. The most likely course of action in Nova Scotia would be to adopt a tariff, similar to that used by utilities in neighboring jurisdictions in the United States, and who have tariffs compatible with FERC rules. But since no such tariff yet exists, and since the entire SMD question is still under intense discussion[8], the entire issue remains unresolved.

As a result of discussions on market scope (see Sect 4.0), and a review of the external pressures bearing on Nova Scotia (see Sect 3.0), the EMGC concluded that the Nova Scotia market and its associated transmission tariff should develop in an evolutionary manner. The table below summarizes committee discussions regarding the starting point and direction for future changes in the design of a transmission tariff for Nova Scotia.

Movement through the chart can be viewed as a surrogate for evolution of the Nova Scotia system. The initial position is at the top left-hand corner with change expected to occur from top to bottom and left to right, or generally from top-left to bottom-right. Each step, or increment in complexity, would require additional administrative support and regulatory burden. Associated costs would be transferred to the system users. The consensus view of the committee was that each increment of change would come about as the appropriate response to a provincial need.

---

[8] FERC Commissioner Brownell recently told a Toronto audience that a final SMD Order may not be issued until late 2003.

Meeting Needs	Nova Scotia Solution	Maritime Solution	North East Solution
Minimal changes by government edict	Y	Y/N	N
OATT, NS/Maritime	Y	Y	N
OATT, FERC 888 compliant	Y	Y	Y/N
OASIS when constraints exist	Y	Y	Y
FERC SMD	Y	Y	Y

As to a possible transmission tariff for Nova Scotia, the EMGC considered three possible options, which are listed below. When the tariff is finally completed, it will be subject to approval by the provincial regulator, the Nova Scotia Utility and Review Board. (UARB).

- Rate Option. An alternative to an OATT would be for NSPI to design a transmission tariff of its own, including rates for access to the system. Such an option would have NSPI determine terms for transmission to allow competitive generation. Terms could be determined by negotiation with individual customers. Such a rate option would not be compatible with FERC criteria for open access, since the terms of access would be controlled by the transmission owner and would not be transparently available to all potential transmission users. Also, it is uncertain whether this option will meet reciprocity requirements from New Brunswick, if they are enforced.
- FERC Order 888 option. This option would create an open access transmission tariff (OATT) in Nova Scotia that followed the *pro forma* approach provided in FERC Order 888. This option had two variants, one with an OASIS and one without. The second variant would not be fully FERC compatible.
- FERC Standard Market Design option. This option would embrace a tariff with all aspects of the Standard Market design (SMD) contained in the FERC NOPR, described above. Several aspects of this approach make it impossible to implement in Nova Scotia at the level of restructuring envisioned by the *Energy Strategy*. The most important issue is the nature of the electricity markets. SMD markets have real-time bid-based wholesale pools with security-constrained least-cost despatch. Such a market is not consistent with the *Energy Strategy* commitment of gradual opening to competition. For Nova Scotia to have such a market, it would have to move all of its electricity supply towards a contracting or competitive framework. In addition, the SMD includes locational marginal pricing (LMP). Under LMP, the prices at different locations in the electricity system depend on the marginal costs of supply at those locations. When there is no congestion on the system, those costs will be the same everywhere. By definition, congestion means that some less expensive generation cannot reach a potential user, so more expensive generation must be used. With LMP, electricity prices at these different locations reflect different generation prices.

The EMGC concluded this discussion with the adoption of the following two recommendations.

Recommendation 1-3. The EMGC recommends the development of a transmission tariff for Nova Scotia which should initially include a scheduling and information system which need not be an OASIS.

Recommendation 1-4. The EMGC recommends that transmission tariffs in Nova Scotia develop towards eventual FERC compatibility.

5.3 Transmission Services Offered

Transmission service need not be an undifferentiated product. The transmission customer can obtain service on either a firm or interruptible basis[9]; they can obtain service that relates to specific transactions or they can use the entire grid. Customers can expect to pay different rates for different levels of service. However, whatever the tariff, electricity flows will obey the laws of physics, and a contract that nominally involves a specific path, will affect flows in other parts of the transmission system.

Transmission service is usually identified as either network, which uses the entire grid (also referred to as Network Integration Service), or point-to-point. A network service customer could, for example, be a generator with a portfolio of generation assets and several customers located in the control area. To transmit power to its customers the generator usually requires the use of the entire grid, and for that reason services are typically sold as "firm".

Point to point service, as the name implies, concerns the transmission of electricity from one specific location on the grid to another. This service would apply to a single generator (or a single generation plant) when selling its power to a single large customer. Point to point service can be sold as either firm or interruptible but when the transmission system is stressed, point to point service is more likely to be interrupted because it is considered to have a lower priority than network service.

To recognize these facts and potential transmission products, the EMGC adopted the following recommendation.

Recommendation 1-5. The EMGC recommends that transmission services that are to be offered under the transmission tariff should initially include:

- ***Network Integration Service for the delivery of both capacity and energy for the supply of load located within the control area***
- ***Point-to-Point service for the reservation of transmission capacity from a specific point of receipt to a specific point of delivery. (Point-to-Point service would be offered on both a firm and non-firm basis).***

An important part of electricity supply is the provision of ancillary services. Ancillary services are required for the operation of an interconnected electricity supply system. For example, one ancillary service is automatic generation control (AGC), which is the ability to follow (without manual intervention) small fluctuations in user requirements (load). Load varies constantly throughout a day, as individual consumers turn appliances and other devices, on and off. Since electricity cannot be stored, the amount being generated must fluctuate exactly with the amount being used.. The provision of an AGC service requires a generation unit that can be automatically controlled for small variations in output. Having AGC is essential to the operation of the electricity supply system.

In a vertically integrated system, ancillary services are provided by the integrated utility. There is no need to provide them independently nor to price them separately. The utility operator typically designs the system to meet the requirements for both energy and services, optimizing for their mutual provision. However, following the functional unbundling of transmission from generation, separate provision must be made for the acquisition of and charging for ancillary services. Further, in a fully competitive market, provision of most ancillary services, can be a source of competition.

In Order No.888, FERC specified several ancillary services which must be offered by all transmission service

---

[9] All transactions are subject to interruption, if necessary to protect the integrity of the transmission system; firm transactions can only be interrupted for such reasons.

providers. All of these services are considered to be mandatory, that is, the service provider must offer them and the customer must purchase some of them from the service provider. Provision of these services is inherent in the system operator function and they cannot be offered competitively. Mandatory services that must be purchased from the transmission provider include: scheduling, control and dispatch and; reactive supply and voltage control.

Other ancillary services, considered to be contestable include: energy imbalance service; regulation and frequency response service; and operating reserves (including spinning, 10-minute, 30-minute and supplemental). These services can be self-provided, bought from other market participants, or provided by the transmission service provider. In any case, they are all necessary for the proper operation of the system.

Under an OATT, all of these ancillary services are offered by the transmission service provider. The EMGC agreed that should also be the case in Nova Scotia.

Recommendation 1-6. The EMGC recommends that the transmission tariff require the system operator to offer each of the following ancillary services:

- **scheduling, control and dispatch**
- **reactive supply and voltage control**
- **energy imbalance**
- **regulation and frequency response service**
- **operating reserve - spinning reserve**
- **operating reserve - supplemental**

5.4 Transmission Tariff Design Issues

The principles of tariff design are the same as those for any regulated rate design. They should ensure that the rates are sufficient to recover the costs, including normal profit; they should assign costs whenever possible to those responsible for causing them; they should be transparent and; they should be fair.

In addition to these general criteria, FERC enunciated six objectives for the design of an Open Access Transmission Tariff. They are:

- *Simplicity*- the tariff should not be unnecessarily complex
- *Pricing Efficiency*- it should include locational pricing where possible
- *Stability*- it should have predictable results over time
- *Competitiveness*- should be encouraged with neighboring utilities
- *Fairness*- it should provide non-discriminatory access to all users
- *Flexibility*- it should possess the capacity for change, as warranted

During the course of its deliberations, the EMGC developed draft recommendations for many transmission tariff design issues. NSPI requested guidance from the EMGC regarding the development of its forthcoming transmission tariff, including several tariff design issues, and the choice of a tariff option. Among the different issues discussed were: the identification of facilities whose costs should be included; the identification of services that would be offered; establishing criteria to allocate revenue requirements associated with those services; establishing billing determinants; defining how congestion on the network would be managed; clarifying the method of pricing and finally allocating interconnection access with other jurisdictions. Each of these issues is dealt with in the following sections.

5.4.1 Definition of Transmission and Distribution

NSPI operates both electricity transmission and distribution systems in Nova Scotia. For the purpose of

unbundling the transmission tariff, these costs must be separately identified. In the United States, FERC issued a series of tests that were developed to assist with determinations that lead to unbundling. They are applied to various wire assets in order to determine if they belong to either the distribution or transmission systems. None of these tests is a single "bright line" assessment, i.e., one single criterion that can be applied definitively, to provide a clear and sharp distinction. Nonetheless, it is generally agreed that the seven characteristics[10] normally listed do represent a reasonable methodology for effecting the required separation

5.4.2 Definition of Transmission - Radials

Within a transmission network, some lines are considered to be radials. Radial transmission lines are extensions, connected to the main system at one end and to a major electricity user or generator at the other. Their attachment to the system is considered to be principally for the purpose of serving that user or generator. An important question in rate design is whether the costs of such radials should be borne by the entities they serve. Alternatively, those costs could be borne by all transmission users or by that group of customers served by similar connections.

A general principle of rate-making for electricity is that parties imposing costs on the system should pay those costs, where such parties can be identified. Against this general principle should be weighed considerations of fairness and equity. It is generally considered fair to charge individual small consumers a common price whether they are located at the end of a long radial line or in an area served directly by the backbone of the system.

Radial lines usually serve either generators or distribution customers. In the case of generation, where a radial line's primary function can be identified as tying a generation station to the grid, the cost of that line can be assigned to the station. In a sense, the cost of the line is as much a cost of generation as the cost of the station itself. A more complex situation is that of radial lines serving distribution. Before the creation of a transmission tariff, rates did not distinguish between transmission and distribution. Today, in some cases where the FERC tests are used the distinction is clear. However, in the case of radial lines, where they serve distribution alone or distribution and generation it is much less clear.

NSPI provided the EMGC with transmission system maps (see appendix) that proposed which lines should be classified as radials and which should be considered as part of the bulk transmission system. NSPI also suggested some 69kV lines that could be classified as transmission and others as distribution. Radial 69 kV lines serving only one load/customer should be grouped with distribution, rather than generation.

Because of a historic anomaly, some parts of the transmission system in Nova Scotia include the 69kV level. The system was built at that voltage to serve load as well as to connect generation to the grid. Several Nova Scotian communities are served by radial 69kV transmission lines of considerable length that have no other transmission related function. Therefore, the committee considers them to be part of the distribution system. The annual revenue required to support these radials is about $6.9 million. Most supply NSPI distribution but some supply municipally owned utilities. Charging the costs of these radials directly to the communities involved would create variable rates for NSPI customers and possibly disadvantage some municipal utilities.

In addition to any transmission radials that might serve generation, some equipment is required to properly connect it to the grid. This equipment includes: step-up transformers to raise the voltage to that of the transmission connection; and some terminal structures which connect generation to the grid. The result of the

---

[10] The seven indicators for distribution assets are: 1. Facilities are normally close to retail customers; 2. Facilities are primarily radial in character; 3. Power flows into, but rarely, if ever out; 4. Power enters but is not reconsigned or transported; 5. Power entering is consumed in a close area; 6. Meters exist at the interface; and 7. Distribution will be at reduced voltages.

assignment of these assets to generation is included in the table below, which shows the impact of removal of several components from transmission revenue requirements. Their removal would not eliminate them, it would just assign responsibility for their cost to particular users or generators.

Cost Implications of Transmission Definitions	
Transmission Component	% of Transmission Revenue Requirement
Generation step-up transformers	2.2%
Radial lines serving generation	2.4%
Radial lines serving load	9.3%

After considering this information, the EMGC made the following recommendation, which removes all of the above components from the transmission revenue requirement. The EMGC chose, in making the following recommendation, to assign costs to those identified as causing those costs. At the same time, it recognized that strict application of this principle might unduly affect some municipal utilities.

Recommendation 1-7. The EMGC recommends using the following principles to determine whether the costs of transmission facilities should be included in the transmission tariff:

- ***The cost of a transmission facility used solely by one party should be assigned or charged to that party***
- ***The cost of transmission facilities that are not part of the transmission backbone should be directly assigned or charged to those parties that use them. The preferred alternative for realizing this objective is:***
  - ***Costs for radial lines serving generators be assigned to those generators***
  - ***Costs for generation step-up transformers be assigned to those generators***
  - ***Costs for radial lines serving distribution loads be assigned to distribution, the revenue requirement to be recovered uniformly from all distribution level customers, supplied by both NSPI and the municipal utilities.***

5.4.3 Charge Determinants

An important early step in transmission tariff design is the definition of charge determinants.[11] EMGC's deliberations in this area began with that task; they were quickly followed by discussions as to how charge determinants should be measured.

In keeping with the principle of assigning costs to those responsible for causing them, transmission tariffs are usually based on peak loads. Load customers are viewed as having caused the need for the transmission, so they are typically responsible for transmission costs.

---

[11] A charge determinant is that characteristic of the customer's electricity use which will determine the charge. For energy purchases, the charge determinant is usually the quantity of energy. For charges intended to recover the fixed cost of maintaining capacity, such as those for the transmission system, the charge determinant can be peak demand. To be decided is how and when that peak demand will be measured.

Charge determinants can be based on peak demand or on energy usage. However, the fixed costs of the transmission system are clearly linked to peak demand on the system. The transmission owner must build and maintain a system large enough to accommodate expected electricity flows at peak times (including sufficient reserve to withstand unplanned system demands). At all other times, the transmission system will have excess capacity.

A given transmission system can accommodate a wide range of energy flows; its size is determined by the peak load. Basing transmission charges on energy usage alone would not correctly assign costs to those responsible for causing them. Since cost is directly linked to peak load, the charge determinant for transmission is the customers's peak load. Peak load charge determinants can be measured either during the customer's peak or during the system peak. Measurements made during the former are called non-coincident peaks (NCP), because the customer's peak demand will not generally coincide with the system peak demand. Measurements made during the system peak demand are referred to as coincident peaks (CP).

The other major issue regarding charge determinants is the interval over which the peak is measured. Any interval can be selected but the longer the period, the higher the peak. Basing transmission tariffs on an annual peak would cause the customer to pay an annual rate based on only one incident of high demand.

For point-to-point customers, charges are determined by their capacity reservation., which is proportional to their use of the system.

After some discussion, the EMGC agreed that an annual peak charge determinant would put too much emphasis on a single incident. Therefore, the Committee adopted the following recommendation.

Recommendation 1-8. The EMGC recommends that transmission revenue requirements be allocated based on the average twelve monthly coincident peaks.

5.4.4 Billing Determinants - Net or Gross Peak

Some transmission customers have the capacity to generate their own electricity. They are unique in that they can , in some instances, be viewed as a generator, while at other times, depending on their ability to supply their own needs, as a load. In some circumstances, system peak demand can vary significantly depending on whether or not they are generating electricity. Self-generators are often large industrial customers who have a need for both heat and power, and build plants to supply both.[12] Generation units in such installations sometimes experience outages resulting from periodic maintenance, equipment failure or simply because the production process may no longer require the heat portion of the generator.

When self-generation is underway, the metered load for the customer is its net load, that is, the total load minus the amount it is self-providing. The total load - that provided from the grid plus self-generation - is referred to as gross load. When the self-generator is operating, it is important to note, the customer is using more services from the grid than are indicated by its net load alone. As long as its generation is synchronized to the grid, it is receiving voltage control services. If its generator should fail, it can expect to receive power from the grid automatically, along with backup support. However, if the self-generator was able to eliminate its load simultaneously with the loss of its generation capacity, it would no longer receive transmission services and backup support from the grid, at least to the extent of its own generation.

The EMGC discussed the issue of appropriate charge determinants for such generators. A charge

[12] Such usages are called cogeneration - the combined production of electricity and usable heat.

determinant which reflected only net load would permit self-generators to place costs on the system without paying for them. On the other hand, charges based on full gross load would result in payment for services that were never received.

One option might involve computation of charges over shorter time periods, since the charge determinant will then more closely approximate net load. Basing the charge on hourly net peak load will result in the self-generator paying for gross load only in those hours when its own generation is not operating. During those times it will take service from the grid. Alternatively, if the charge is set yearly, based on annual net peak load, the customer will pay for gross load in any year that its own generation was not operating, even for a short time.

The EMGC considered this to be an important issue. The *Energy Strategy* instructed the EMGC to recommend ways to encourage cogeneration. Under current tariffs, cogenerators pay on a net load basis. If cogenerators were forced to pay transmission tariffs based on gross load, it would act as a major deterrent to entrants. A position between the two extremes of gross load and net load is monthly net peak load. With that charge determinant, a self-generator would pay for gross load only for those months when its generation was not operational. This would likely result in higher transmission charges for cogenerators, but less than that resulting from a full gross load tariff. Recognizing the potential impact on existing self-generators, the EMGC recommended a different charge determinant for them.

The EMGC considered the cost implications of these charge determinants for customers with their own generation and adopted the following recommendation.

Recommendation 1-9. The EMGC recommends that the billing determinants to establish transmission charges for network customers be monthly net non-coincident peak demand and that for point to point customers it should be reserved capacity (estimated on a net load basis, if necessary.) The charge basis for existing self-generation customers would be hourly net non-coincident peak.

5.4.5 Rates - Location and Voltage

The final issue for rate design is whether transmission charges vary by customer location: either geographically within the province or electrically (i.e., in terms of the voltage level at which the customer is connected). In general, the impact of location on transmission costs is that the greater the distance over which electricity travels the greater the losses in the system. Adding loads in regions distant from a source of generation will increase losses proportional to usage. Adding load in areas close to generation can decrease losses by allowing more distant generation to serve more distant loads.

Transmission tariffs have two components: a fixed cost contribution and a variable cost component. The variable component recovers costs that vary over time, such as congestion costs. The fixed component recovers the fixed costs of the system, including its capital costs. Within a system containing a single transmission service provider, fixed costs are charged on a postage-stamp tariff; that is, all transmission system users pay the same rate per unit of charge determinant (typically peak load), regardless of the distance between the user and the generator. Using transmission between adjacent systems produced a separate charge.

The advent of multiple-transmission system organizations, such as Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs), encompassing the territory of more than one transmission service provider eliminate the charges between transmission service providers in the same ISO or RTO. It then forces a choice between transmission service charge methodologies. The two choices regarding rates are postage stamp rates, under which all transmission customers within the ISO or RTO pay the same rates,

or license plate rates, under which each transmission customer pays the rate set by its own service provider, and then has access to the entire system.[13] Both approaches are in use by some ISOs; for example, the Pennsylvania-New Jersey-Maryland (PJM) ISO uses a postage stamp rate for all customers within the ISO; the New York ISO uses a license plate rate.

The EMGC considered the question of whether a postage stamp rate should vary according to the voltage level at which the customer is connected. The argument advanced is that a customer connected to the system, at a high voltage level, is receiving no services from low voltage transmission or distribution; consequently they should not have to pay for them. An alternative view is that all transmission customers benefit from the entire system and its high degree of interconnectedness. Further, some committee members felt that there is also the issue of fairness; if a customer is simply located close to a high-voltage transmission line, then they would have a much lower cost to access that line.

The EMGC agreed that the transmission tariff should be based on a postage stamp rate, but asked for more information before deciding whether the charge determinant should include voltage.

The EMGC approved the following recommendation.

Recommendation 1-10. The EMGC recommends that the transmission tariff rate design be based on a consistent charge regardless of the location of the connecting customer, and that in addition new transmission customers be assessed locational factors relating to transmission losses, which may be negative or positive.

5.5 Congestion Management Policies

The phrase "transmission congestion"refers to the fact that sometimes electricity generated in one part of the system cannot reach its destination in another part, because demand for access exceeds capacity. Transmission system congestion means that cheaper generation is available, but cannot reach the load so more expensive generation will be used in its place. The cost of congestion is the difference between cheaper generation that would have been scheduled, and the more expensive generation that is scheduled. This situation can sometimes occur between Nova Scotia and New Brunswick when cheaper generation is available in the former but the capacity of the lines between both provinces is fully utilized. The end result is that cheaper generation must be idled in Nova Scotia while more expensive generation is used in New Brunswick. The approaches used to address congestion internal to the province, as opposed to that which occurs on the interties connecting the provinces, are different and will be treated separately.

5.5.1 Management of Internal Congestion

One way to manage internal congestion is to have locational marginal pricing, with differential prices at different points in the system. Prices would change frequently, as the conditions of supply and demand change. The difference in price between two points at any time reflects the cost of the constraint to the system, and is the value of relieving the constraint by one unit. That value changes constantly as supply and demand conditions change. Without a real time market, Nova Scotia cannot use locational marginal pricing, since there will be no real time price basis for it.

---

[13] This nomenclature comes from the obvious analogy with a postage stamp that costs the same everywhere in the country and will move a piece of mail to any destination within the country. A vehicle license fee is set by the issuing jurisdiction, but allows the vehicle to be driven freely anywhere within the country.

Nova Scotia will therefore have a single pricing zone for transmission[14]. Within that zone congestion costs can be shared by all participants, or they can be assigned to the participant causing the congestion. Identifying which generator or user is causing congestion at any given moment is impossible. All participants in the system have the capacity to increase or relieve congestion simply by increasing or decreasing their usage. Therefore, when congestion occurs the cost incurred in a single price zone system must be shared.

However, at the time a new facility is attached to the system, it is possible to analyze the flow of electricity before and after its connection. That analysis can identify the potential for the new facility to cause congestion. If new congestion is predicted then the entity responsible could be required either to mitigate the expected impact, by adding any required system upgrades, or by paying additional congestion-related fees.

The EMGC adopted the following recommendations.

Recommendation 1-11. The EMGC recommends that all existing customers share the congestion costs on the existing system.

Recommendation 1-12 The EMGC recommends that new generators and major loads be required to pay:

- ***All costs to connect to the transmission network.***
- ***All costs of system upgrades required to mitigate congestion costs that they would otherwise create***
  - ***Generators who agree to be constrained down if this alleviates the congestion to a level consistent with what previously existed will not be charged for additional congestion costs***
- ***Any direct transmission system benefits from the investments charged to the generator or load (e.g., reduced losses or reduced congestion costs that are borne by other parties) will be paid to the generator or load.***
- ***Any direct benefits or costs due to the impact of the new generation or load on total system losses will be paid or charged to the new generation or load.***
- ***The generator will be responsible only for the cost of advancing construction facility upgrades if the transmission service provider has previously identified them as required for reliability purposes.***

5.5.2 Transmission Rights on the Interties

Nova Scotia's only direct connection to another province is with New Brunswick. Those connections (interties) between the two provinces are valuable assets, demonstrated by their use by Emera Energy to export power to Prince Edward Island through New Brunswick. NSPI indicated to the Committee that transactions over the interties reduce its annual revenue requirement by approximately $1.6 million.

The Transmission Tariff will identify how transmission rights on the interties are allocated, of which there are several choices: the rights could be auctioned to the highest bidders; they could be assigned to existing market participants on the basis of existing usage; or they could be assigned on a priority basis to participants according to the length of the export contracts they propose to undertake. After much discussion, the EMGC concluded that it needed additional information on this issue and consequently requested that the consultant produce a detailed paper on this topic.

However, the Committee will discuss the creation of a system of import and export rights, and for the distribution of the benefits of their use that resulted in the following recommendations.

Recommendation 1-13. The EMGC recommends that Nova Scotia maintain a system of import and export transmission rights for electricity and capacity.

Recommendation 1-14. The EMGC recommends that the system of transmission rights be designed to preserve the heritage benefits of transmission interconnections.

APPENDIX A

Terms of Reference
for
Nova Scotia's Electricity Marketplace Governance Committee
(EMGC)

Purpose

The Electricity Marketplace Governance Committee (EMGC) will report to the Minister of Energy and recommend the implementation, development, structure, economic considerations, and rules to introduce limited electricity competition in Nova Scotia

Energy Strategy Electricity Objectives

- To maintain access to secure, reliable, and affordable electricity generated in an environmentally responsible manner.
- To encourage long-term competition..
- To promote the growth of renewable energy sources in Nova Scotia.

Energy Strategy Policy Directions

The energy strategy made some high level policy decisions regarding the degree of electricity restructuring that will take place in Nova Scotia by 2005, which are highlighted below. The strategy also flagged policy needs for the longer term related to renewable performance standards and possibly increased competition.

- The government will work with Nova Scotia Power Inc. (NSPI) and other industry stakeholders to carefully and gradually open up the electricity marketplace in Nova Scotia.
- As a first step toward opening the markets, the government will create an EMGC, which will seek input from a broad range of stakeholders to develop detailed recommendations regarding the subsequent implementation of the specific electricity restructuring measures announced in the energy strategy.
- Introduce competition within the electricity sector in a staged and measured process beginning with supply to wholesale customers (currently six municipal utilities).
- Authorize open access transmission on NSPI facilities for all generators selling to wholesale customers or export markets.
- Introduce competition for new electricity generation capacity.
- Assist the development of an independent power producer's (IPP) renewable sector by permitting these IPPs sited in Nova Scotia to wheel 'green power' directly to customers, and setting a voluntary target of 2.5% (50MW) for new renewable generation by IPPs.
- Encourage the development of co-generation.
- Allow net metering for customers with micro-generation units.

EMGC Chairperson

In order to expedite the commencement of work and get the EMGC operational as soon as possible, the chairperson of the EMGC will be appointed by government.

The ideal candidate for this paid position will possess the following qualifications:

- independent expert with no direct connections to any of the major stakeholders in the Nova Scotia's electricity marketplace;
- possess a good understanding of the electricity issues that the EMGC will be required to resolve;
- possess excellent organizational and administrative skills;
- be a diplomatic negotiator;
- be able to work to very demanding time lines;
- possess excellent oral, written, and presentation communication skills;
- be familiar with the key stakeholders in the Nova Scotia electricity marketplace; and
- possess a thorough understanding of the functional operation of government.

The contracted chairperson should be given a one year appointment, and paid on a per diem basis at a rate and time allocation to be negotiated between the government and the selected candidate.

EMGC Membership

The membership in the EMGC will include a broad range of stakeholders. The committee will be comprised of representation from the following organizations:

- NSPI (1 representative covering its range of business functions - generation, transmission, distribution, customer service);
- municipal utilities (1 representative from organization of municipal electric utilities);
- large customers (1 representative chosen from Canadian Manufacturers and Exporters);
- medium sized customers (1 representative chosen from the Electricity Consumers Alliance of Nova Scotia);
- residential consumers (1 representative from the Consumers Association of Canada);
- independent renewable power producers (1 representative from the Renewable Energy Industries of Nova Scotia);
- small business (1 representative from Canadian Federation of Independent Business).

In addition, the following organizations will be invited to have observer status at the meetings:

- Nova Scotia Department of Energy;
- Nova Scotia Utility and Review Board. (1 observer/representative);
- Chambers of Commerce (1 representative from the Association of Chambers of Commerce).

EMGC members will be compensated for travel expenses incurred to attend EMGC meetings.

EMGC Support Services

The EMGC will have requirements for administrative services and may require occasional staff and consultant services, which will be coordinated through the Energy Department. Some of the issues to be resolved by the EMGC will require the assembly of additional information materials. The EMGC will link with the electricity policy group of the Energy Department and other government officials (for example: environment, business development, municipal affairs, etc.) as required.

Public Input to the EMGC

The EMGC members represent both their own organizations and other stakeholders in their constituency group. EMGC members will consult with these stakeholders in order to bring wider participation to the process. Aside from the input received from its membership, the EMGC must also facilitate input from other interested Nova Scotians. This will be accomplished through the public posting of all EMGC background materials, minutes, decisions, work plans, timetables etc. on a web site and encouraging individuals to submit their views on relevant issues to the EMGC for consideration and public posting on the website.

Deliverables and Time Lines

The EMGC will have one year, commencing April 2002, to make recommendations to the Energy Minister on several complex issues related to wholesale competition, open access transmission, and renewable generation of electricity. The Committee is expected to deliver several interim reports, followed by a final report at the end of December, 2002.

The EMGC will be required to publically post meeting minutes, background materials, interim reports outlining its progress on key decisions, and ultimately, its final report outlining its list of specific recommendations to the Energy Minister

Overview of Key Market Design Issues and EMGC Responsibilities

Group 1 - Responsibilities to be reported on initially by December, 2002

- Recommendations on ensuring that transmission system access is available to all market participants on an equitable basis.
- Establishment of exit fees or other method for handling stranded costs.
- Responsibility for the non-contestable market (standard offer supply).
- Which customers are entitled to standard offer supply?
- The definition of renewable energy for policy purposes.
- How is new capacity added to the Nova Scotia generation system?

Group 2 - Responsibilities to be reported on initially by December, 2002

- Design of a system that retains for existing Nova Scotia consumers, the benefits of the low-cost system that they have already paid for, i.e. 'heritage assets'.
- Recommendations on the promotion of co-generation (definition, transmission access, etc.).
- How will green power marketers get access to end-use customers? Would the access in effect require physical or financial contracts between the marketer and the customer?
- What will the role of NSPI be with respect to green power in the medium and longer term?
- If the contracts are financial, how can the sellers of green power be monitored to ensure that they only sell the green power once?
- If/when a Renewable Portfolio Standard is to be implemented, what is the target capacity and time frame to achieve it? To which market participants does it apply?
- Under what circumstances should net metering be permitted? Encouraged?

Longer term issues to be reported on beyond December, 2002 (scope as yet to be finalized)

- Recommendations on creating and maintaining workable competition in the Nova Scotia electricity marketplace (market power issues).
- Recommendations on market surveillance and enforcing adherence to market rules.
- Mechanisms to determine when new investments or competitive supplies create stranded costs.
- Compatibility of the Nova Scotia system with those in the Northeast region (US and other Canadian

jurisdictions).
- Issues of reciprocity and the relation to transmission developments in both Canada and the United States.
- Ability of the Nova Scotia electricity market to evolve over time as necessary.

Relationship with the UARB

The EMGC will be making recommendations to the Energy Minister regarding implementation of the energy strategy. The energy strategy sets the high level direction. The EMGC will rely on the experience of its members and extensive consultation to provide much more detail on implementation, in order to achieve overall strategy objectives. These EMGC recommendations will be used by the Energy Minister to implement changes to legislation, regulations and government policy.

The Nova Scotia Utility and Review Board (UARB) regulates Nova Scotia Power Inc., which will remain a regulated utility. The UARB will continue to oversee NSPI, approve rates for NSPI electricity service, approve open access transmission rates, determine the requirement and timing for new generation capacity, approve the structure and fees for customers accessing 'green power', etc. The UARB has ultimate authority for implementation and oversight based on the overall rules set by government.

APPENDIX B

Summary of Recommendations

Recommendation 1-1. The EMGC recommends that NSPI develop and file a transmission tariff. (Section 5.1)

Recommendation 1-2. The EMGC recommends that any transmission tariff developed for use in Nova Scotia ensure open and non-discriminatory transmission access for all market participants. (Section 5.1)

Recommendation 1-3. The EMGC recommends the development of a transmission tariff for Nova Scotia which should initially include a scheduling and information system which need not be an OASIS. (Section 5.2)

Recommendation 1-4. The EMGC recommends that transmission tariffs in Nova Scotia develop towards eventual FERC compatibility. (Section 5.2)

Recommendation 1-5. The EMGC recommends that transmission services that are to be offered under the transmission tariff should initially include:

- ***Network Integration Service for the delivery of both capacity and energy for the supply of load located within the control area .***
- ***Point-to-Point service for the reservation of transmission capacity from a specific point of receipt to a specific point of delivery. (Point-to-Point service would be offered on both a firm and non-firm basis). (Section 5.3)***

Recommendation 1-6. The EMGC recommends that the transmission tariff require the system operator to offer each of the following ancillary services:

- ***scheduling, control and dispatch***
- ***reactive supply and voltage control***
- ***energy imbalance***
- ***regulation and frequency response service***
- ***operating reserve - spinning reserve***
- ***operating reserve - supplemental (Section 5.3)***

Recommendation 1-7. The EMGC recommends using the following principles to determine whether the costs of transmission facilities should be included in the transmission tariff:

- ***The cost of a transmission facility used solely by one party should be assigned or charged to that party.***
- ***The cost of transmission facilities that are not part of the transmission backbone should be directly assigned or charged to those parties that use them. The preferred alternative for realizing this objective is:***
  - ***Costs for radial lines serving generators be assigned to those generators***
  - ***Costs for generation step-up transformers be assigned to those generators***
  - ***Costs for radial lines serving distribution loads be assigned to distribution***
  - ***The revenue requirement to be recovered uniformly from all distribution level customers, supplied by both NSPI and the municipal utilities. (Section 5.4.2)***

Recommendation 1-8. The EMGC recommends that transmission revenue requirements be allocated based on the average twelve monthly coincident peaks. (Section 5.4.3)

Recommendation 1-9. The EMGC recommends that the billing determinants to establish transmission charges for network customers be monthly net non-coincident peak demand and that for point to point customers it should be reserved capacity (estimated on a net load basis, if necessary.) The charge basis for existing self-generation customers would be hourly net non-coincident peak. (Section 5.4.4)

Recommendation 1-10. The EMGC recommends that the transmission tariff rate design be based on a consistent charge regardless of the location of the connecting customer, and that in addition new transmission customers be assessed locational factors relating to transmission losses, which may be negative or positive. (Section 5.4.5)

Recommendation 1-11. The EMGC recommends that all existing customers share the congestion costs on the existing system. (Section 5.5.1)

Recommendation 1-12 The EMGC recommends that new generators and major loads be required to pay:

- ***All costs to connect to the transmission network.***
- ***All costs of system upgrades required to mitigate congestion costs that they would otherwise create.***
  - ***Generators who agree to be constrained down if this alleviates the congestion to a level consistent with what previously existed will not be charged for additional congestion costs.***
- ***Any direct transmission system benefits from the investments charged to the generator or load (e.g., reduced losses or reduced congestion costs that are borne by other parties) will be paid to the generator or load.***
- ***Any direct benefits or costs due to the impact of the new generation or load on total system losses will be paid or charged to the new generation or load.***
- ***The generator will be responsible only for the cost of advancing construction facility upgrades if the transmission service provider has previously identified them as required for reliability purposes. (Section 5.5.1)***

Recommendation 1-13. The EMGC recommends that Nova Scotia maintain a system of import and export transmission rights for electricity and capacity. (Section 5.5.2)

Recommendation 1-14. The EMGC recommends that the system of transmission rights be designed to preserve the heritage benefits of transmission interconnections. (Section 5.5.2)

APPENDIX C

Glossary

Agent
Buys or sells on behalf of trader.

Aggregator, Broker, Marketer, Agent & Trader
A profit-motivated entity that acts as an intermediary in arranging transactions between, or on behalf of, generators and customers. It may assemble load or generation into larger blocks (aggregator), act as a negotiator between buyers and sellers (broker), or buy, sell and take physical positions in the marketplace (marketer).

Ancillary Services
Ancillary services are those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission system. Ancillary services typically include operating reserves, regulation and frequency imbalance, scheduling, control and dispatch, and voltage support and control. FERC Order 888 named energy imbalances as an ancillary service.

Automatic Generation Control (AGC)
Equipment that automatically adjusts electricity generation, within a power control area, from a central location.

Available Transfer Capability (ATC)
A measure of the remaining physical capability in a transmission network for commercial activity, over and above that already committed to users. Already committed uses would include commitments for both system reliability and commercial transactions.

Backup Supply Service
The provision of capacity and energy to a market participant, either when needed to replace the loss of its generation sources, or to cover that portion of demand that exceeds the generator's capacity to supply for more than a short time.

Baseload Capacity
That category of generating capacity, because of its low operating costs, tends to operate continuously and steadily. Its output is generally not varied to follow changes in demand

Bilateral Contract Market
A market with direct contracts between buyers and sellers to obtain generation and/or ancillary services of a given type, duration, timing and reliability over a contractual term. A bilateral contract market is an alternative to using a centralized power pool or organized exchange auction to make purchases or sales of power or ancillary services.

Black Start Capacity
An ancillary service that provides an offsite source of power to enable a Control Area to restore its system, or enables a generator to start its generating units or restore service to its customers if local power is not available. Sometimes referred to as restoration service.

Bus
An electrical connection point between different parts of the interconnected system, such as the connection between a generating facility and the transmission grid in a power station switchyard. Also referred to as a "node."

Capability
The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity
The maximum power that a generating unit, generation station, or other electrical apparatus can supply, usually expressed in megawatts.

Capacity Reserve Market
An hourly market in which the market operator purchases generating capacity additional to that required to meet demand and operating reserve requirements in a given future hour.

Co-generator
A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam) used for industrial, commercial, heating, or cooling purposes.

Congestion
The conditions under which the transactions that market participants wish to implement exceed the transfer capability of the transmission grid. Congestion usually requires the system operator to adjust the output of generators, decreasing output in one area to relieve constraint while increasing it in another to continue to meet customer demand.

Congestion Pricing
A method of pricing in which all energy bought and sold in the operator-administered spot market settles at market-based prices that account for the effects of congestion. Settlement prices are determined from the marginal cost (price) of serving an increment of load at each location.

Coincident Peak
The amount of metered demand at the time of the system peak. Monthly coincident peak is at the time of monthly peak.

Connection Asset
Any line, transformer or other piece of transmission equipment that is required to connect a generator or load to the common transmission grid. Typically, connection assets are used by only one to several entities, and electrical flows tend to be in one direction only.

Constraint
A restriction on a transmission system, or segment of a transmission system, that may limit the ability to transmit power between, and hence to inject or withdraw power at, various locations. Constraints may be the result of physical limitations, such as the thermal limits of a transmission line or local voltage and stability restrictions, but can also include contingency limits, that assure secure operations in the event of an unexpected failure of a transmission or generation facility.

Control Area

A region on the electricity grid where supply and demand are kept in balance through dispatch by the system operator.

Cost of Service Regulation
See **Rate of Return Regulation**.

Decommissioning
The act of permanently removing a facility from service. In the case of a nuclear plant this includes safely closing, and possibly dismantling (or otherwise disposing of) the existing facilities at the end of their service life.

Demand Side Management (DSM)
Measures undertaken to control the level of energy usage at a given time, by increasing or decreasing consumption or shifting consumption to some other time period. Consumers, utilities or third parties can undertake DSM efforts.

Demand Bid
A bid submitted to the market indicating the price a purchaser is willing to pay for a specified quantity (MWh or kWh) of electricity.

Direct Load Control
Refers to program activities that can interrupt consumer under direct control of the utility system operator. This type of control usually involves residential consumers. Direct Load Control excludes Interruptible Load and other Load Management effects.

Dispatch
The process by which the System Operator directs the real time operation of a supplier or a purchaser to cause a specified amount of electric energy to be provided to or taken off of the system. Dispatch control includes instructions to synchronize, desynchronize, increase or decrease electrical output and any other instruction relevant to maintaining system security.

Dispatchable Demand
Customer demand that can be adjusted in response to dispatch directions from the System Operator.

Embedded Generation
Generation that is not directly connected to the transmission grid, and is usually within a distribution system.

End-use Consumer or Customer
A residential, commercial, or industrial customer in the energy marketplace who buys energy for its own consumption and not for resale.

Energy Imbalance Service
Provides correction for any hourly mismatch between a transmission customer's energy supply and the demand the customer is obligated/contracted to serve.

Enforceable
With reference to agencies being charged with monitoring and enforcing the Market Rules and protocols the

agency must have the power to impose sanctions on market participants who violate the Market Rules and the process of investigation of breaches of Market Rules and protocols must be transparent.

Exit Fee
A fee that can be charged when a customer switches electricity suppliers, the purpose of which is to provide for the recovery of stranded costs attributable to the departing customer.

Fairness
With reference to the market design in relation to participants and category of participants the market design should not artificially discriminate. In addition actions taken to enforce the market rules should follow written rules and protocols.

FERC
Federal Energy Regulatory Commission. Federal counterpart to state utility regulatory commissions in the United States that regulates the price, terms and conditions of power sold in interstate commerce and regulates the price, terms and conditions of all transmission services. FERC's Order 888, issued in 1996, defines the requirements under which regulated monopolies and power pools must provide non-discriminatory access to participants engaging in wholesale transactions.

Financial Bilateral Contract
A form of agreement between two parties to trade electricity at a price determined by the parties. Also known as a Contract for Differences.

Financial Transmission Right
A tradable contractual right to a payment based on the difference between energy prices at different locations.

Firm Transmission Service
Point-to-point transmission service that is reserved and/or scheduled that is of the same priority as that of the transmission provider's firm use of the system.

Forward Contract
An agreement between two parties in which they agree to the purchase or the sale of a commodity at some future time under fixed conditions.

Futures Contract
A standardized, tradable agreement between a buyer and a seller to purchase a specified quantity of a commodity (e.g. electrical energy) of specified characteristics, at a later date at a fixed price.

Futures Market
A market in which standardized contracts for the future delivery of commodities or financial instruments are traded.

Futures Option
A contract that confers the right, but not the obligation, to buy a specific quantity of a commodity at a specified price and delivery location.

Generator
An entity that owns and operates an electricity generation facility.

Governance

The process and structure used to direct and manage the business and affairs of a corporation with the objective of enhancing shareholder value, which includes ensuring the financial viability of the business.

Green Energy
Output from certain generation sources identified as "green" because they meet certain standards for being deemed environmentally preferable.

Greenfield Investments
Investments in new generation or transmission facilities that are located on new sites, rather than at sites with existing facilities.

Gross Load
Within a distribution system, the total load, including that served by embedded generation.

Incumbent Utility
The existing utility that serves customers, and in some instances may benefit from its existing customer relationships.

IPPs
Independent Power Producers. Generators owned by entities other than an electric utility.

Independent System Operator (ISO)
A system and market operator, who is independent of other market interests, i.e., has no ownership interest in the transmission facilities and no vested interest in specific market outcomes.

Integrated System
The electric system encompassing generation, loads, transmission and distribution facilities.

Interface
The set of transmission interconnections between any two regions.

Intermittent Power Source
A generator, such as a wind turbine, whose output may vary considerably over short periods due to the variability and unpredictability of its external energy source.

Intertie
A transmission line that connects two adjacent control areas.

Interruptible Load
Arrangements made between consumers and the System Operator in which the consumer agrees to shed load at the direction of the System Operator, in exchange for compensation. Customers may offer this load to the System Operator as Operating Reserve.

Interval Meter
An electricity meter that is able to record and track a customer's electricity consumption over time so that the consumption in each unit of time can be matched with the cost of power during that period of time.

Kilowatt-hour (kWh)

A standard unit for measuring electricity. Residential customers' rates are usually expressed in cents per kilowatt-hour.

kWh Metering
Metering capable of measuring the total usage or flow of kilowatt-hours on a continuing basis, but not capable of recording and tracking such usage over shorter intervals, such as every hour.

LBMP
Location-based marginal pricing. (see LMP)

LDC
Local Distribution Company. An entity that owns a distribution system for the local delivery of energy to consumers.

Least-Cost Dispatch
The scheduling of power production as demand for electricity varies, according to the lowest cost generation sources available to the System Operator, given transmission limits and other constraints.

License Plate Rate
A transmission rate design under which the transmission charges are set by the transmission service provider for the customer and give access to other transmission systems in the same pool at no additional transmission charge.

Light-Handed Regulation
A streamlined regulatory method designed to speed up the process and reduce the cost while balancing the interests of the various parties and allowing the regulator to carry out its statutory duties.

LMP
Locational marginal pricing, or locational pricing. A form of congestion pricing that determines the price of energy at locations on the grid as the marginal cost of serving an increment of load at those different locations.

Load
The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy consuming equipment of the consumer.

Load Profile
An approximation of the amount of energy typically taken during each hour by a consumer or class of consumers over a defined period, such as monthly, given the total amount of energy metered for that defined period. Load profiles are needed for consumers who do not have interval meters, and are used to allocate total kWh usage over the month to each hour, in order to perform settlements that are based on hourly prices.

Load Shedding
The process by which the system operator deliberately removes (either manually or automatically) preselected customer demand from the power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Loop Flow
Unscheduled flow that arises from the physical nature of electricity whereby it follows the path of least resistance. Loop flow occurs on transmission paths other than the path contracted for by transacting parties.

Also referred to as parallel path flow.

Losses
The energy that is consumed (lost) in the transmission and distribution of electricity from generation to load.

LSE
A load-serving entity. Historically, electric utilities that had an obligation to serve consumers. An LSE can be distribution utility if it supplies energy in addition to wires services and competing entities that take on a contractual obligation to serve retail consumer.

Market-Clearing Price (MCP)
The price at which a market clears, such that there are no further gains to be made from further trading. In competitive wholesale pool markets, all electricity bought and sold is settled at MCP (in the absence of congestion).

Market Concentration
A measure of how market share is distributed among competing firms.

Market Model (Wholesale)
A theoretical description of the structure and functions of a wholesale electricity market.

Market Operator
The entity with the responsibility to operate the real time spot market for electricity and any other centrally administered forward markets.

Market Participant
Any entity that is authorized by the market rules to produce, buy, sell, trade, or transmit energy and/or ancillary services.

Market Power
The ability of a seller, or group of sellers acting in concert, to profitably maintain prices above competitive levels for a significant period of time.

Market Power Mitigation
The means by which a firm's ability to exercise market power is discouraged, limited or prevented.

Market Scope
Amount or share of the total electricity demand that is open to competitive supply.

Market Share
An individual firm's share of the total market sales revenues.

Market Transparency
The ability of market participants to observe and understand the workings of the market.

Megawatt (MW)
Unit of electrical power, used to measure the generating capability capacity of a generating station or the maximum demand of an electricity consumer.

Megawatt-hour (MWh)
A measure of the energy produced by a generating station over time: one megawatt of power produced for

24 hours provides 24 megawatt-hours of energy (as does 24 megawatts produced for one hour).

Merchant Generator / Plant
An electric generating facility that is built without any sales commitments.

Meters or Metering
Equipment that measures and registers the amount and direction of energy quantities over a period of time.

Monopoly
A single firm which is the sole producer of a commodity for which there is no close substitute.

Monopsony
A market characterized by a single buyer of a product. See **Single Buyer Market**.

Native Load
The wholesale and retail customers on whose behalf the Transmission Provider, by statute, franchise, regulatory requirements, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

NEPOOL
New England Power Pool.

NERC
North American Electric Reliability Council. An association of electric utilities established in 1968 in response to the 1965 blackout in the Northeastern U.S. and Ontario. Through the work of 10 regional councils and one affiliate council, NERC members ensure the reliability of the integrated North American bulk power system. NERC develops standards, guidelines and criteria for assuring system security and evaluating system adequacy, and has succeeded in maintaining a high degree of grid reliability throughout North America.

Net Coincident Peak
The amount of metered energy at the time of the system peak, net of any self-generation.

Net Metering
In many jurisdictions, electricity customers are allowed to produce their own electricity through renewable energy sources and "sell back" any unused capacity to their local utility grid. Put simply, net energy metering means that any kilowatt-hours produced and fed back into the grid by a customer are subtracted from the kilowatt-hours of electricity obtained from the utility, resulting in net kilowatt-hours.

Network Integration Service
Transmission service that allows a transmission customer to integrate, plan, economically dispatch, and regulate its network resources to serve its network load in a manner comparable to that in which the transmission provider utilizes its transmission system to serve its native load customers. Network Integration Transmission Service also may be used by the transmission customer to deliver non-firm energy purchases to its network load without additional charge.

Network Transmission
All transmission facilities 69kV and above, except those radial circuits with uni-directional flow (serving single customers, single generation facilities, or distribution substations)

Nodal Pricing

A form of LMP in which the (clearing) price for electricity is determined at individual nodes or buses within a transmission system.

Non-Discriminatory Access
The rules that assure that all market participants have access to the market, the transmission system, distribution systems and ancillary services under the same terms and conditions, with no preferential treatment for those entities who may own, or be affiliated with the owners of, transmission system or distribution system assets.

Non-Firm Transmission Service
Point-to-point transmission service that is scheduled and paid for on an as-available basis and is subject to interruption.

Non-Utility Generators
See IPPs.

NOPR (Notice of Proposed Rulemaking)
A designation used by FERC for some of its proceedings or dockets. A NOPR is issued in advance of a rule-making, inviting comments to FERC.

NPCC (Northeast Power Coordinating Council)
One of the 10 regional councils under NERC, it is composed of all the major interconnected utilities in Ontario, Quebec, the Maritimes, New York and New England.

OASIS (Open Access Same-Time Information System)
The information system and standards of conduct contained in Part 37 of the Federal Energy Regulatory Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS. The OASIS will provide information by electronic means about available transmission capability for point-to-point service and will provide a process for requesting transmission service. OASIS will enable Transmission Providers and Transmission Customers to communicate promptly requests and responses to buy and sell available transmission capacity offered under the Transmission Provider's tariff.

OATT (Open Access Transmission Tariff)
The terms and conditions of OATTs were established by FERC Order 888. The primary objective of an OATT is to ensure that transmission service providers offer transmission service to others under equivalent terms and conditions as it provides such service to itself and its affiliates.

Option
A contract that gives the right, but not the obligation, to buy a commodity or asset for a fixed price at, by, or before a specific date.

Peaking Capacity
Generating capacity typically used only to meet the peak demand, the highest demand for electricity during the day. Peaking capacity is typically provided by hydroelectric generators or gas-fired combustion turbine generators.

Peak Load/Peak Demand
The electric load that corresponds to a maximum level of electricity demand in a specified time period.

Performance-Based Regulation (PBR)

Any rate-setting mechanism that attempts to link rewards (usually profits) and penalties to desired results or targets.

Point-to-Point Service
Point-to-point service provides a customer the ability to use only that portion of a transmission owner's integrated facility to input power at a specified point and take out the power at a specified point regardless of actual flow.

Pool
Term sometimes used to refer to the generation dispatch coordinated by the System Operator, based on bids to sell and offers to purchase submitted by market participants, and the associated settlement system.

Postage Stamp Rate
A rate for transmission service that does not vary according to distance from the source of the power supply.

Power Marketers
Business entities engaged in buying and selling electricity, but which do not own generating or transmission facilities.

PPA (Power Purchase Agreement)
An agreement that set forth the terms and conditions for the sale of power.

Projected Marginal Energy Cost
The projected sum that has to be paid for the next increment of product or service. The marginal cost of electricity is the price to be paid for kilowatt- hours above and beyond those supplied by available generating capacity.

Ramp Rate
The rate, expressed in megawatts per minute, at which a generator can increase or decrease its output.

Rate
The price charged for a commodity or service. Rates may be subject to regulatory approval or may be set by the marketplace.

Rate of Return Regulation
Process of regulation whereby the regulator sets rates at a level that will cover operating costs and provide an opportunity to earn a reasonable rate of return on the invested property devoted to the business. Also known as Cost of Service Regulation.

Regulation
The oversight of a market by an administrative agency or regulator, including any intervention in the markets to set rates and other terms and conditions under which the regulated service must be provided. Traditional electric regulation attempts to put a monopoly under restraints to achieve prices (rates), output and investment levels comparable to those that would occur under a competitive market.

Regulator
An entity that, through power of law or some other legitimate means, has the authority to impose regulation.

Reliability

Reliability is considered to be one of the most important characteristics of any electricity supply and refers to the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply.

Renewable Portfolio Standard
A requirement that a certain amount of electricity sold in a competitive market include some amount produced from approved renewable sources.

Retail Market or Retail Access
A market in which electricity and other energy services are sold directly to consumers by competing suppliers. Also known as Direct Access.

Retailer
An entity that purchases electricity for the purpose of selling electricity to a consumer or acting as agent or broker for a consumer or another retailer with respect to the sale of electricity.

RFP (Request for Proposals)
A process for obtaining competing proposals from providers of a service or product.

Robustness
Robustness refers to the ability of Market Rules and protocols to function well under a wide range of market circumstances.

RTO (Regional Transmission Organization)
An entity independent of market participants that is responsible for the operation of the transmission system and administration of the transmission tariff. FERC's requirements for RTOs were first set forward in Order 2000.

SBC (Systems Benefits Charge)
A charge placed on electricity end users to create a fund used for various social purposes, such as energy efficiency programs or equalization of rates for rural or remote customers.

Self-Regulation
A regulatory approach whereby industry participants develop and administer the rules governing their operations, subject to appeal to a government regulator.

Single Buyer Market
A market with a monopoly buyer facing competitive suppliers. In electricity restructuring, it can be a first step towards competition from a vertically integrated monopoly utility structure. See **Monopsony**.

Spot Market
A market in which goods are traded for immediate or near-immediate delivery. In many electricity market designs, the market operator would operate and administer settlements for a spot market, in which suppliers could submit bids to sell and purchasers could submit offers to buy energy through a coordinated auction, with settlements based on market-clearing prices. Market participants are free to use the spot market to sell/purchase energy at market-clearing prices, as needed.

Spot Market Prices

The market-clearing prices determined in a spot market and used as the basis for settlements for all purchases and sales in that spot market.

Stand-by Charge
A charge imposed on a transmission customers to have access to the grid and the generation and ancillary services provided by the grid. Traditionally, stand-by charges have been imposed on customers who relied on the grid only intermittently, on a "stand-by" basis.

Stranded Costs/Investment
Costs that cannot be recovered from market prices. With respect to electricity competition, stranded investments are those assets owned by a utility that would become uneconomic in a competitive market.

Strike Price
With reference to bilateral contracts, the price at which parties to the contract have agreed to trade and to settle their transactions.

Substation
Facility equipment that switches, changes, or regulates electric voltage.

System Operator
The entity with the responsibility to monitor and control an electric system in real time. (The term can also refer to the individual at an electric system control centre who is monitoring and controlling the electric system in real-time).

System Losses
Percentage of kWh's injected in to the system that was not ultimately billed to the customer. Losses can be due to line or transformation losses, errors in billing or billing estimates or theft of power.

Tariff
The terms and conditions under which a service or product will be provided, including the rates or charges that users of service or product must pay. Tariffs are usually proposed by the service or commodity provider, and are subject to regulatory approval. Typically, the rates and terms for obtaining transmission service are set forth in a tariff.

Time-of-Use Meter
A meter capable of measuring and recording the amount of electricity used during defined set periods for which specific tariffs for electricity consumption are applicable, such as daytime peak, nighttime off-peak, winter, summer.

Trader
Buys or sells on own account, but generally does not take delivery.

Trading Period
The time period in the marketplace for which physical trades are defined. The trading period for most short-run electricity markets is an hour or half-hour. All bids, offers, nominations must be defined in terms of the trading period (e.g. half-hour, hour etc.). Each trading period has its own schedule and dispatch, as well as its own market-clearing price and settlement.

Transformer
Apparatus which increases or decreases the voltage (the "pressure," as opposed to the current strength) at which electricity flows.

Transmission
The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Transmission Backbone
(See Network Transmission)

Transmission Services
The acceptance, transmission and delivery of power within a Control Area. May include specific ancillary services.

Transmission Tariffs
The authorized charges levied for provision and use of transmission services.

Transparency
Transparency refers to the degree with which the market rules and protocols are simple enough to fulfill the goals of market efficiency and market function. In addition, under this principle actions by the market operator and system operator should be capable of audit and verification and market information should be available to all market participants on a timely basis.

UARB
The Nova Scotia Utility and Review Board.

Unbundling
The breaking down of a bundled service into its component parts so that a customer can choose to purchase different components of the service from different parties. When LDCs offered only bundled services, their customers could purchase electricity only from the LDC. In an unbundled environment, the customer can choose to purchase its electricity supply from any supplier it wants and the LDC provides delivery to the customer's meter. Additional unbundling may allow other parties to provide other components of service, such as billing, meter reading, and credit and collection services.

Vesting Contracts
Contracts that are entered into prior to the start of a new market. Typically vesting contracts are used to assure that the benefits (or costs) of key resources owned by the incumbent utility are captured by (or imposed upon) consumers for some defined period after competition begins.

Wheeling
The use of an interconnected transmission system to implement electricity transactions that transmit power into (wheeling in), within, out of (wheeling out) or through (wheeling through) that system.

Wholesale Market
This refers to the market in which electricity and other energy services are sold to wholesalers/retailers/distributors (who in turn sell to retail or end-use customers). A wholesaler/retailer/distributor of power would have the option to buy its power from a variety of generators or suppliers, and the generators or suppliers would be able to compete to sell their power to a variety of wholesalers/ retailers/distributors.

Wholesale Pool Market
Term used to refer to a security-constrained least-cost generation dispatch coordinated by the system

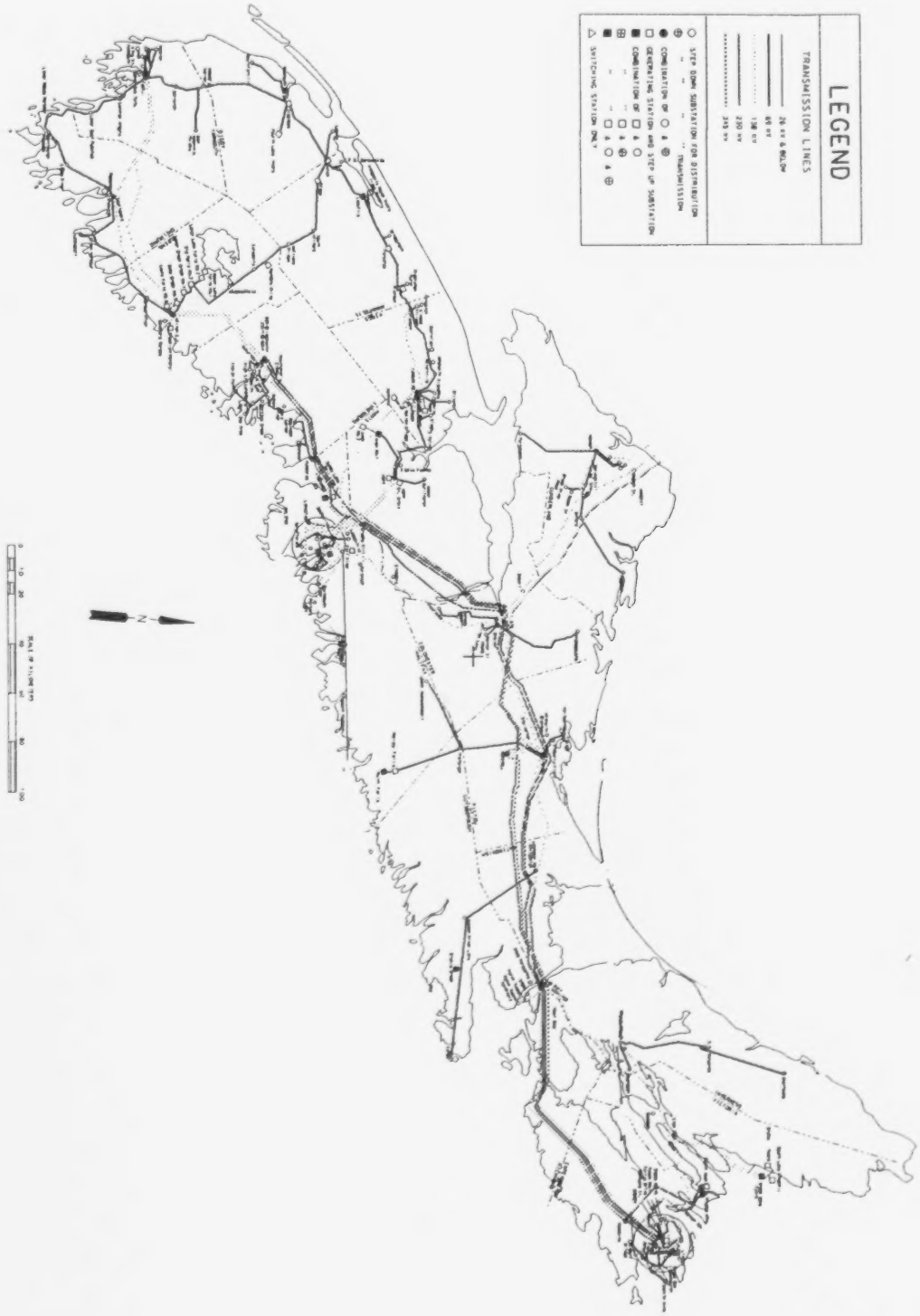
operator, based on bids to sell and offers to purchase submitted by market participants, and the associated settlement system.

Zonal Pricing
A form of LMP in which the price for electricity is determined for specific regions or zones (as opposed to points or nodes) of a transmission system.

APPENDIX D

NSPI Transmission Lines

DETAILS



Nova Scotia Power Inc.

A.P.P. 2000-11

LHH 1998-12

SYSTEM OPERATING MAP OF NOVA SCOTIA
GENERATING STATIONS AND TRANSMISSION LINES

Y 1 0 1 P 0 0 0 0 0 0 1

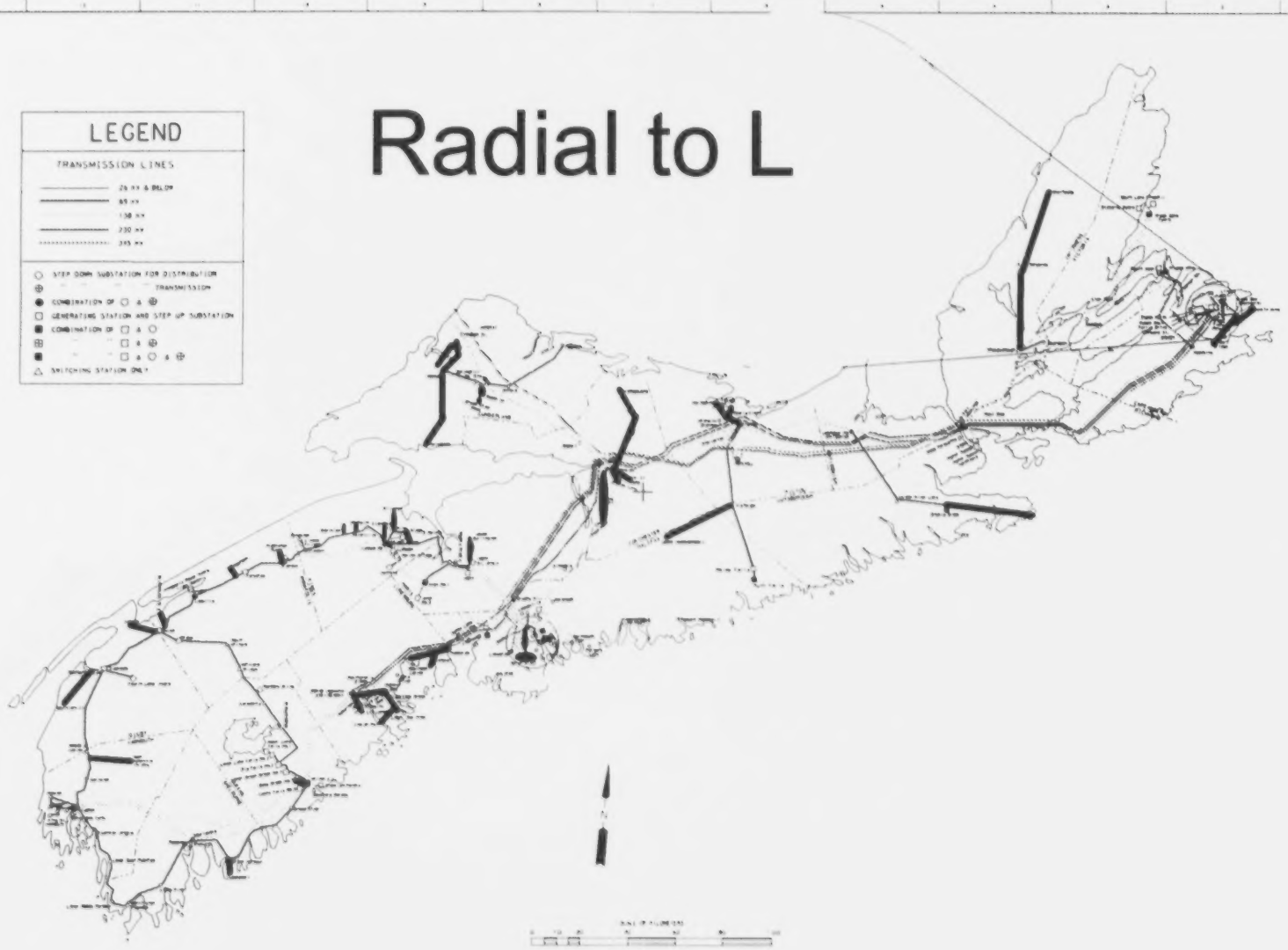
3

APPENDIX E

NSPI Transmission Lines

Radials to Load

Radial to L



REF. or DRAWING No. 1.0.1.P. 0.0.0.0.0.1

DETAILS

SYSTEM OPERATING MAP OF NOVA SCOTIA
GENERATING STATIONS AND TRANSMISSION LINES

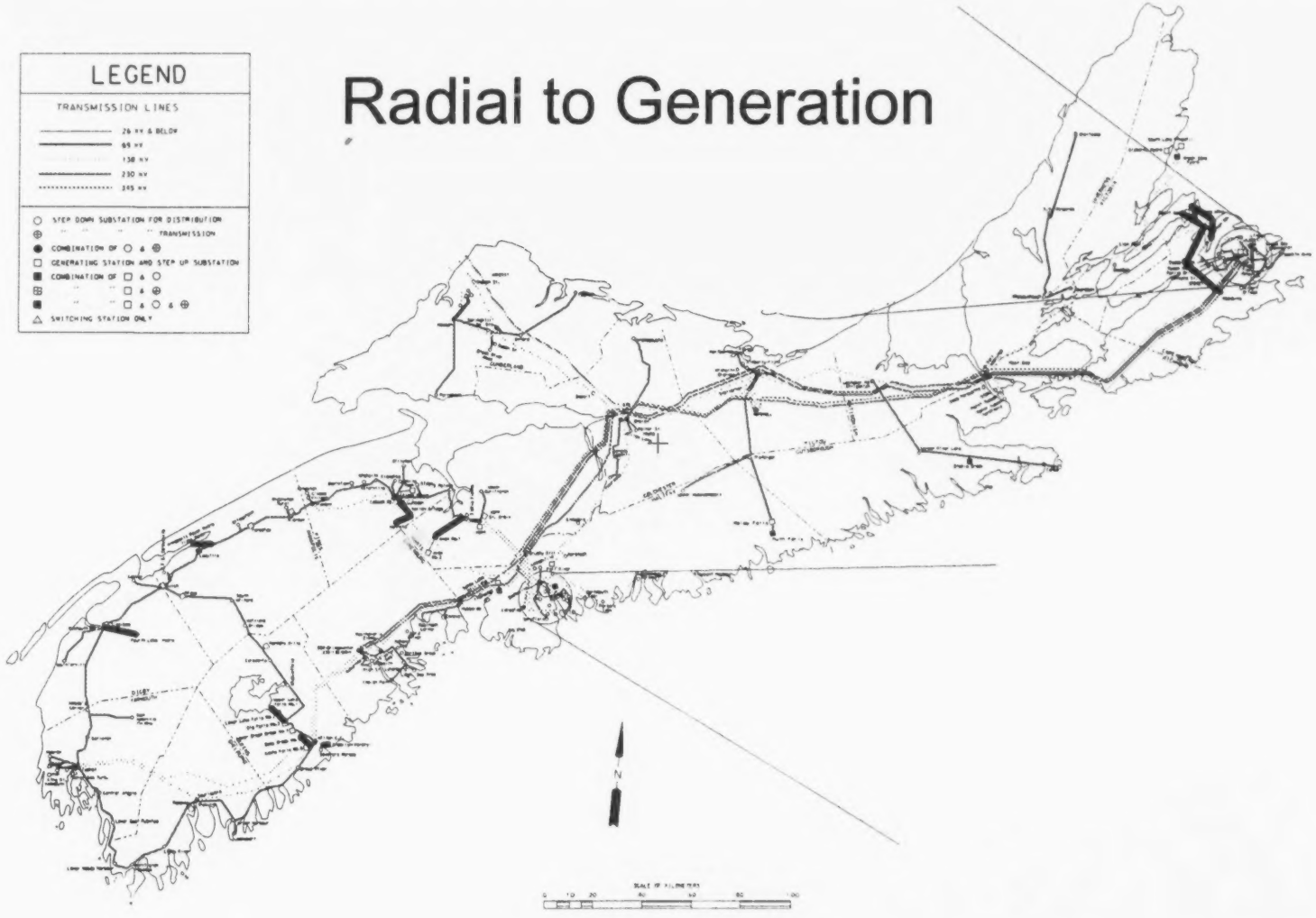
1.0.1.P. 0.0.0.0.0.1

APPENDIX F

NSPI Transmission Lines

Radials to Generation

Radial to Generation



DETAILS

SYSTEM OPERATING MAP OF NOVA SCOTIA
GENERATING STATIONS AND TRANSMISSION LINES

Nova Scotia Power Inc.